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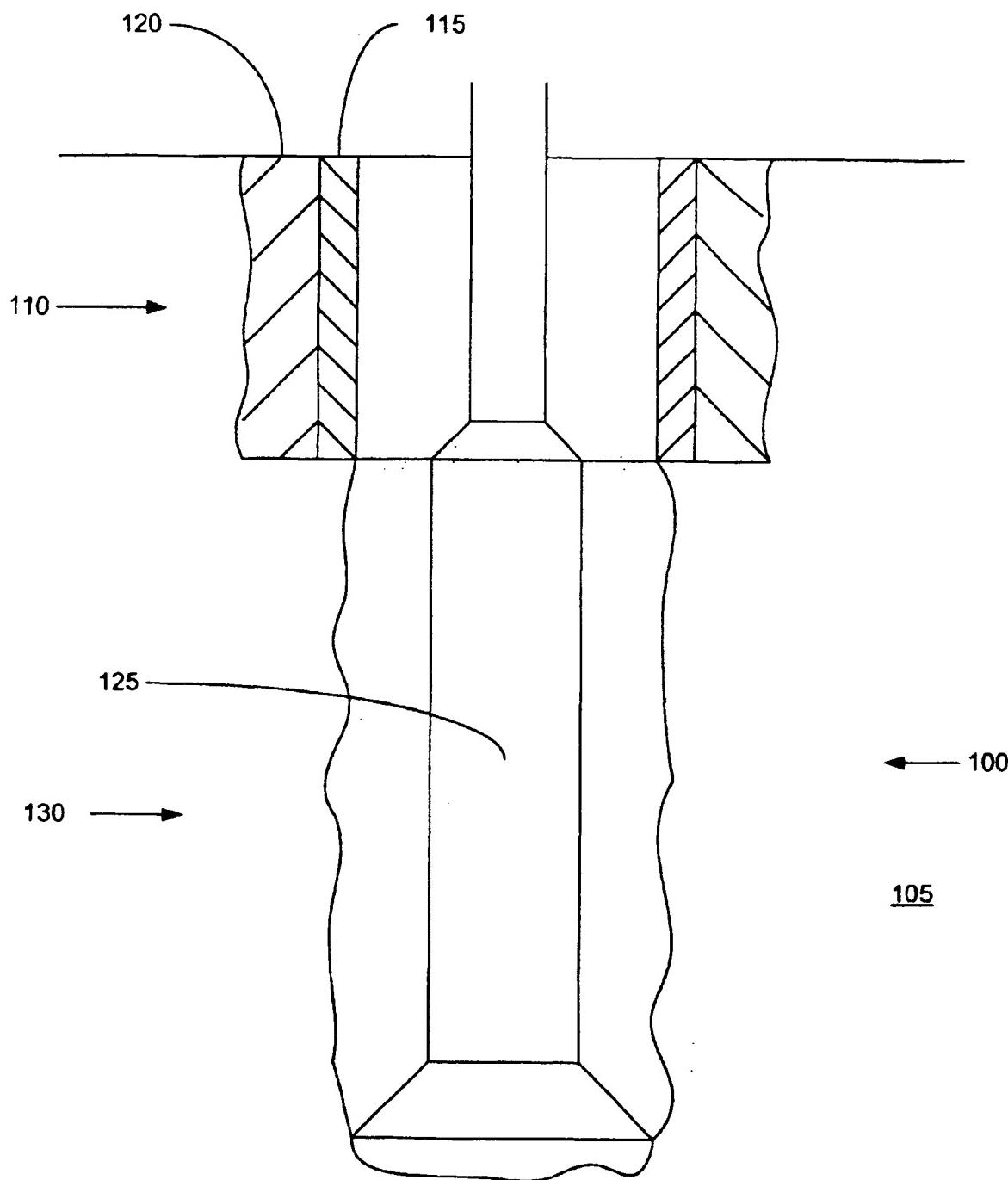
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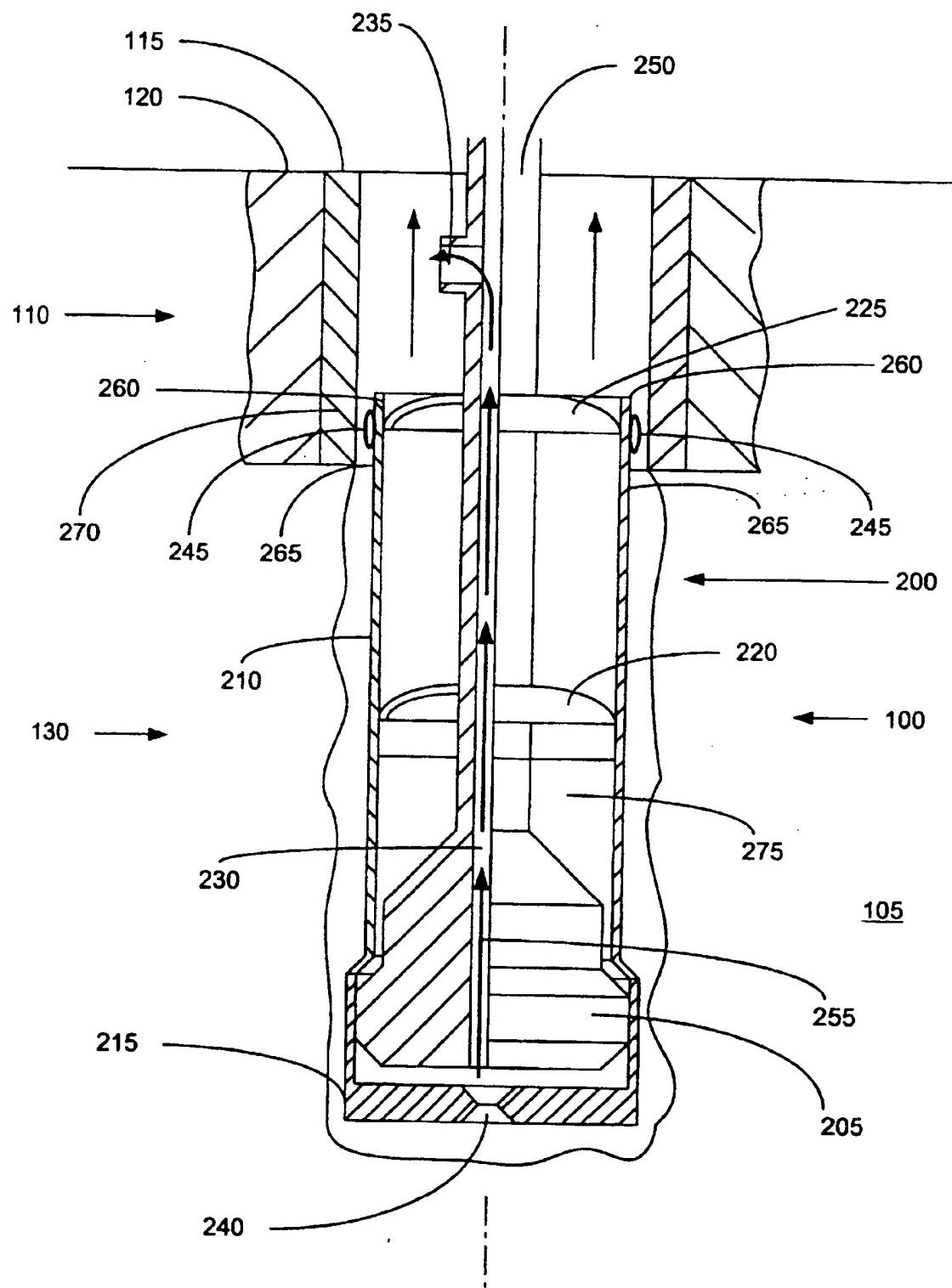
(54) Title of the invention: Forming a wellbore casing while simultaneously drilling a wellbore

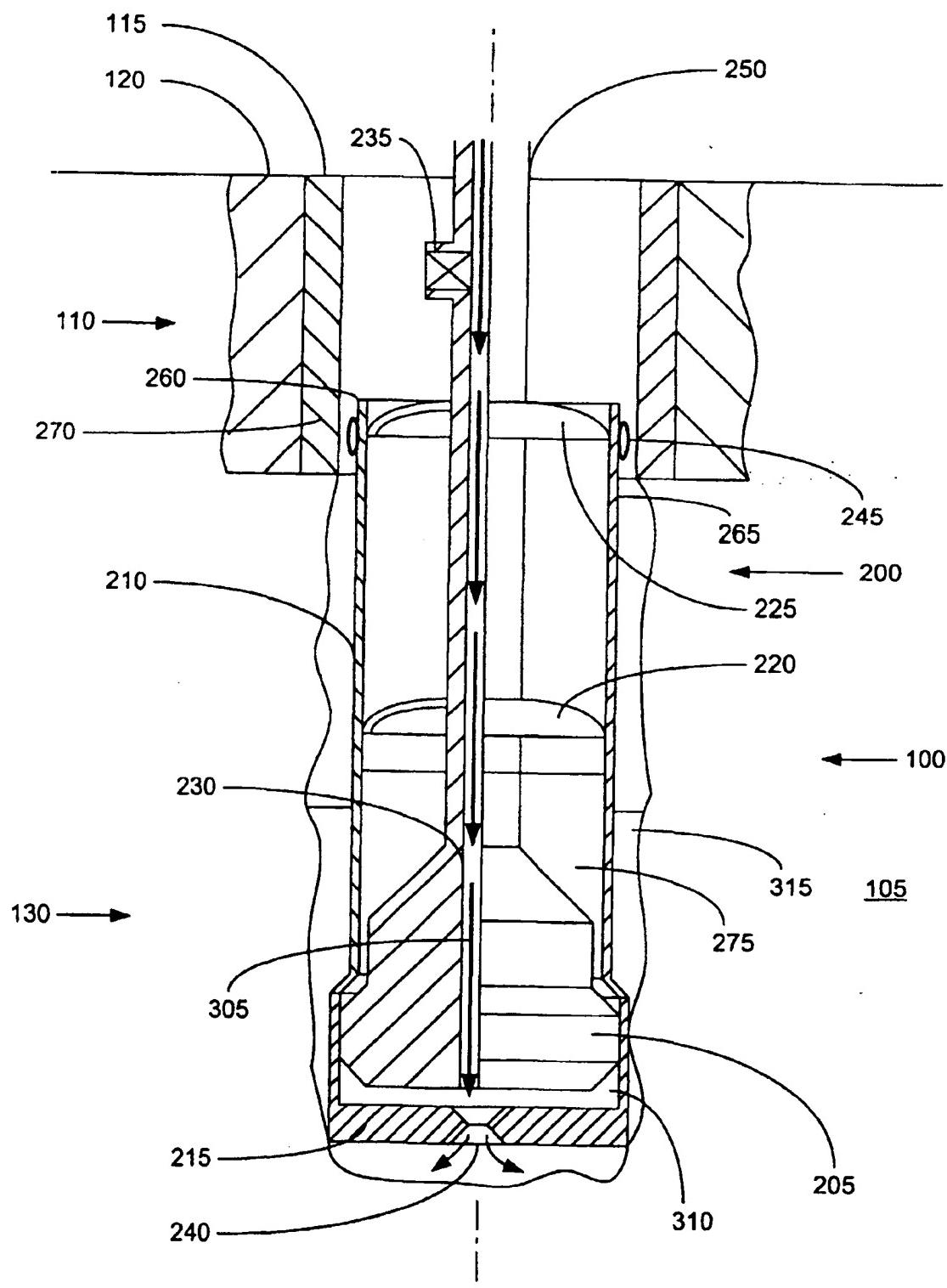
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2385623

**FIGURE 1**

**FIGURE 2**

**FIGURE 3**

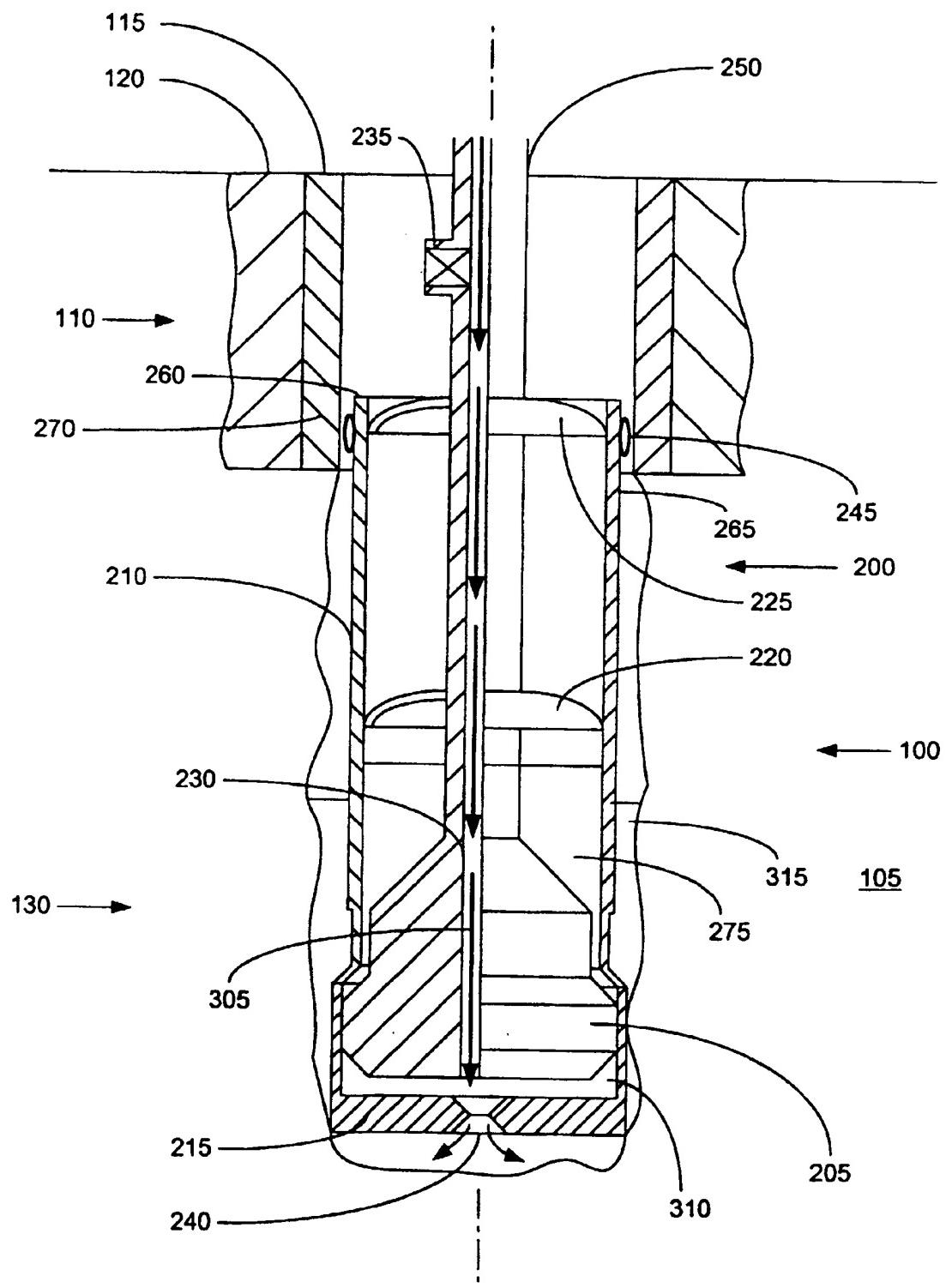
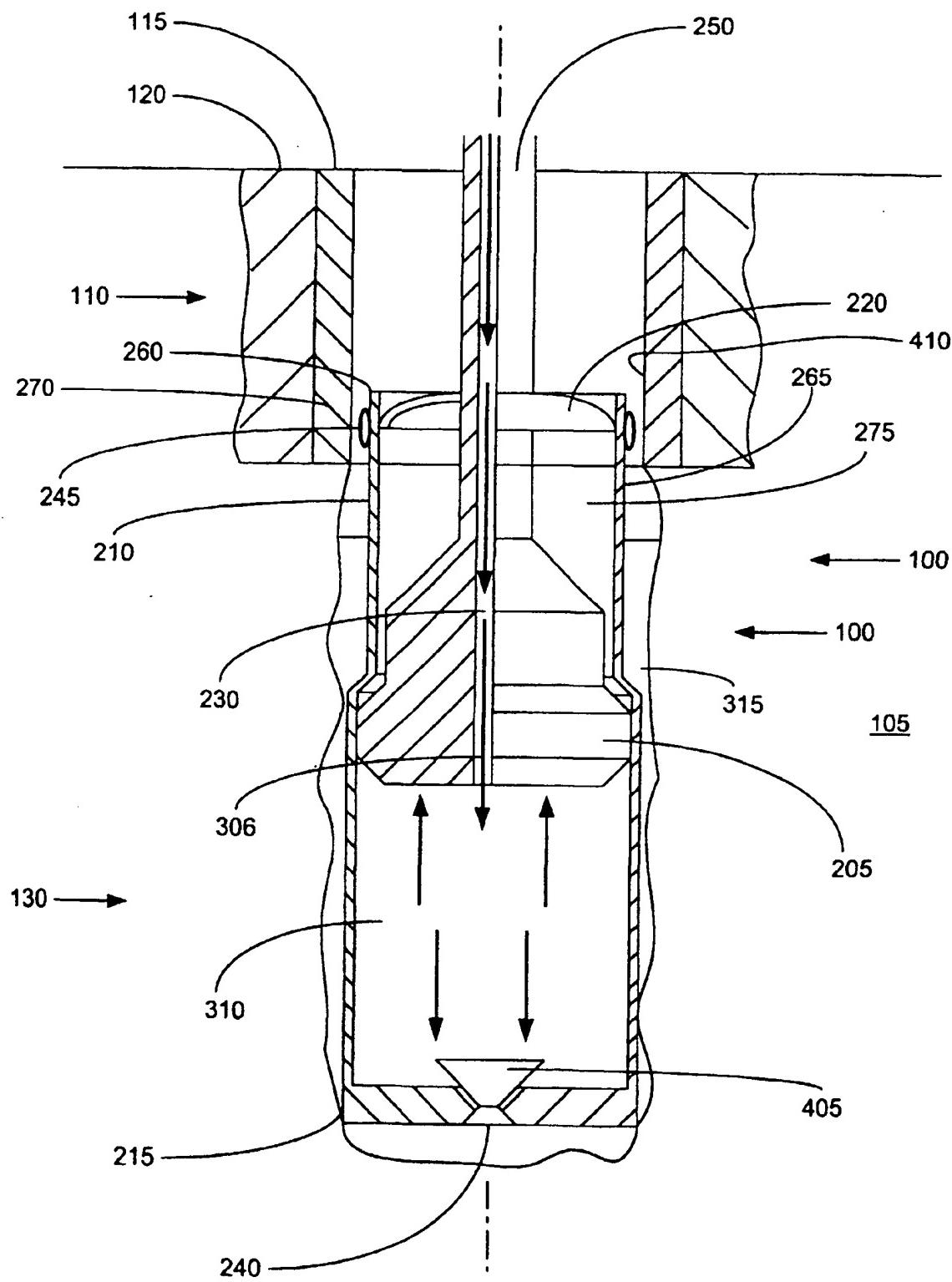
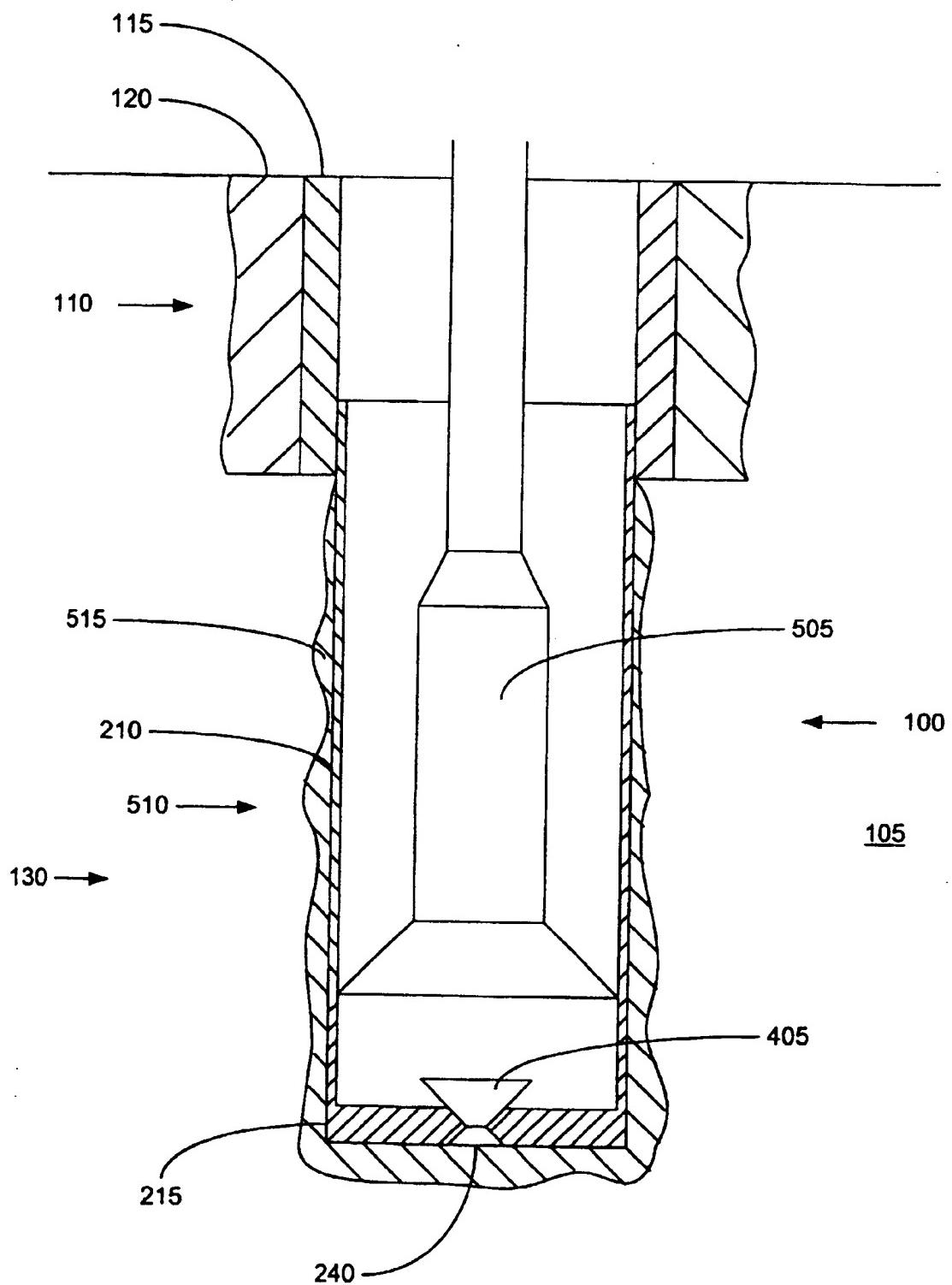


FIGURE 3a

**FIGURE 4**

**FIGURE 5**

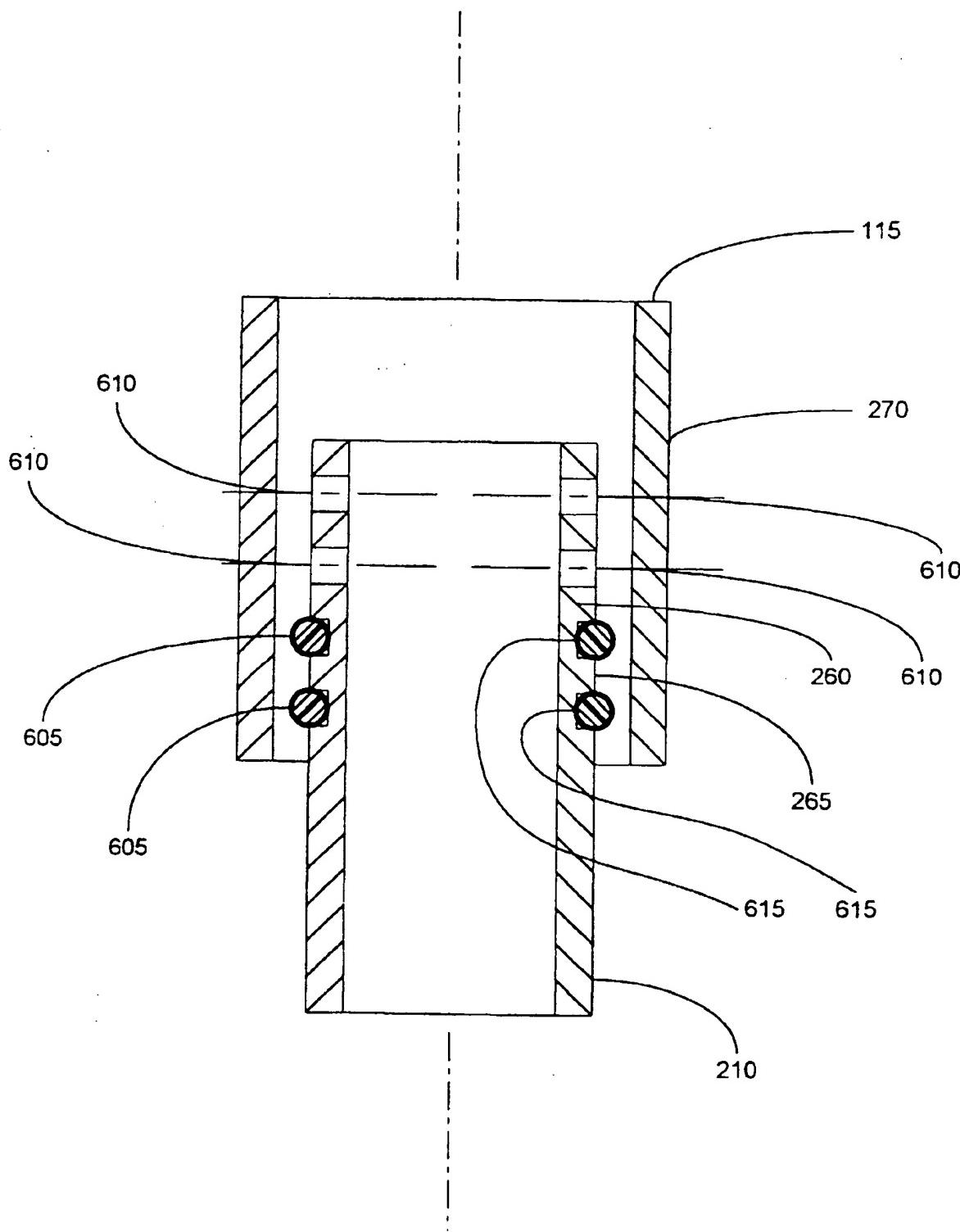
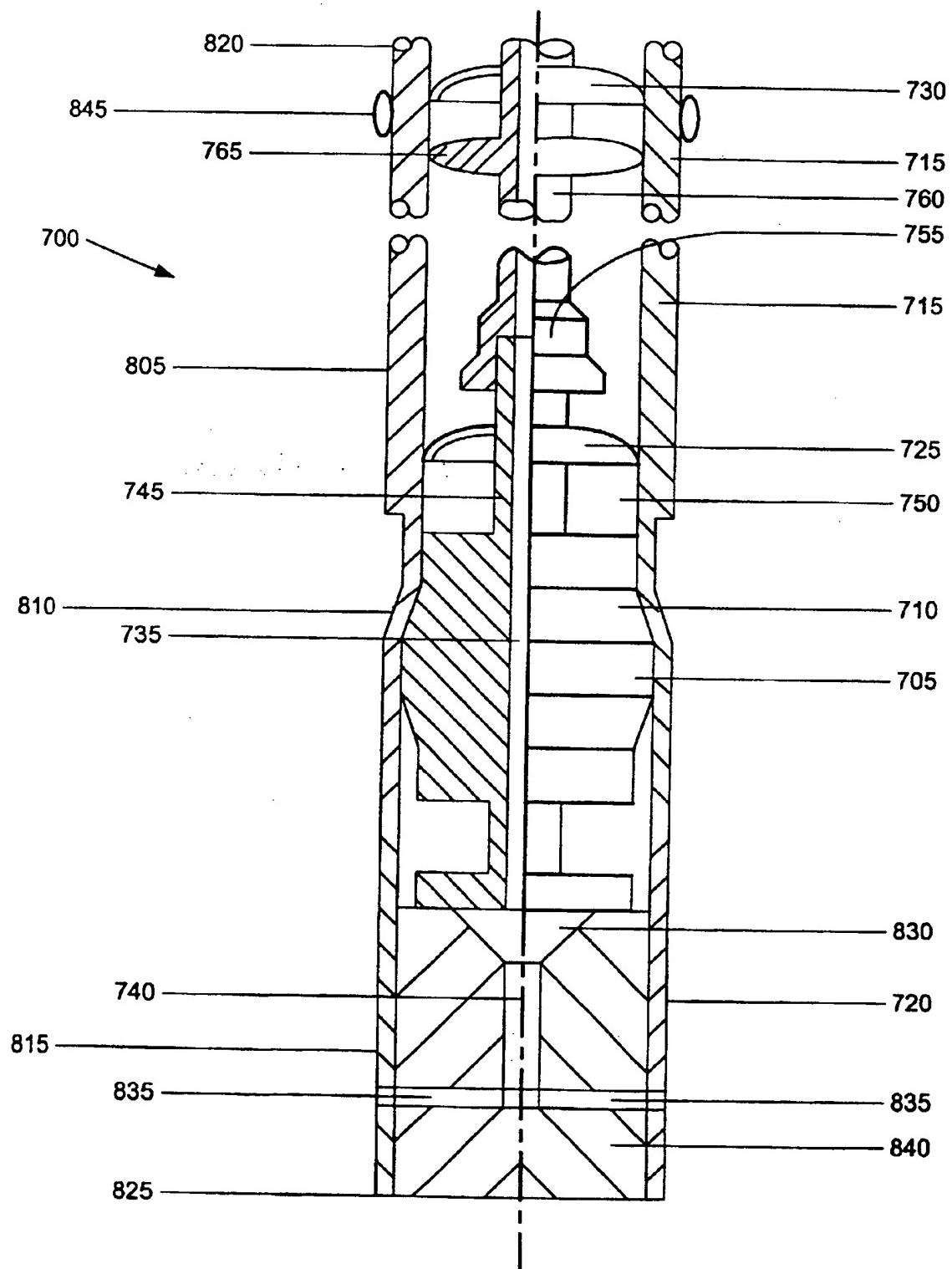
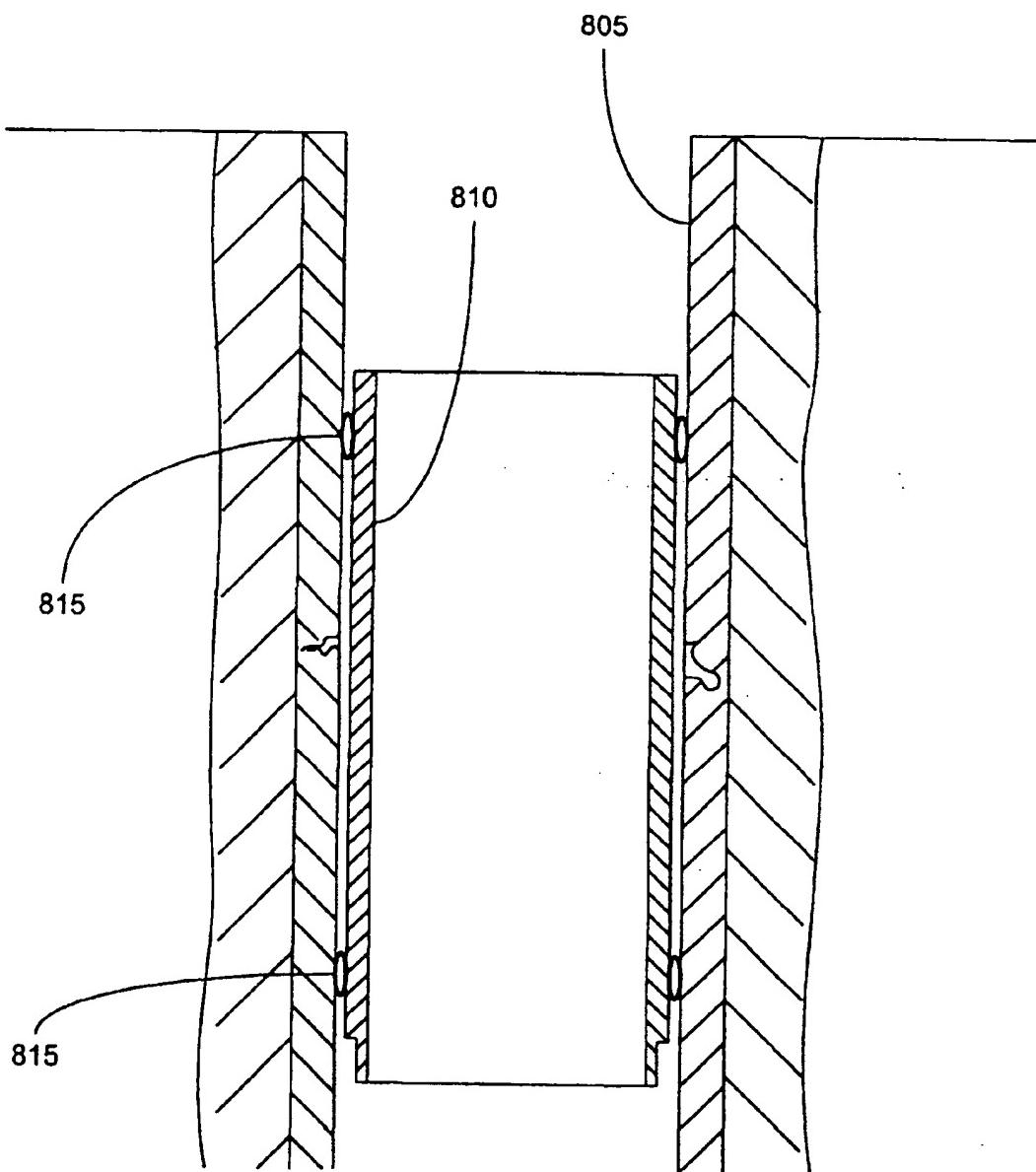


FIGURE 6

**FIGURE 7**

**FIGURE 8**

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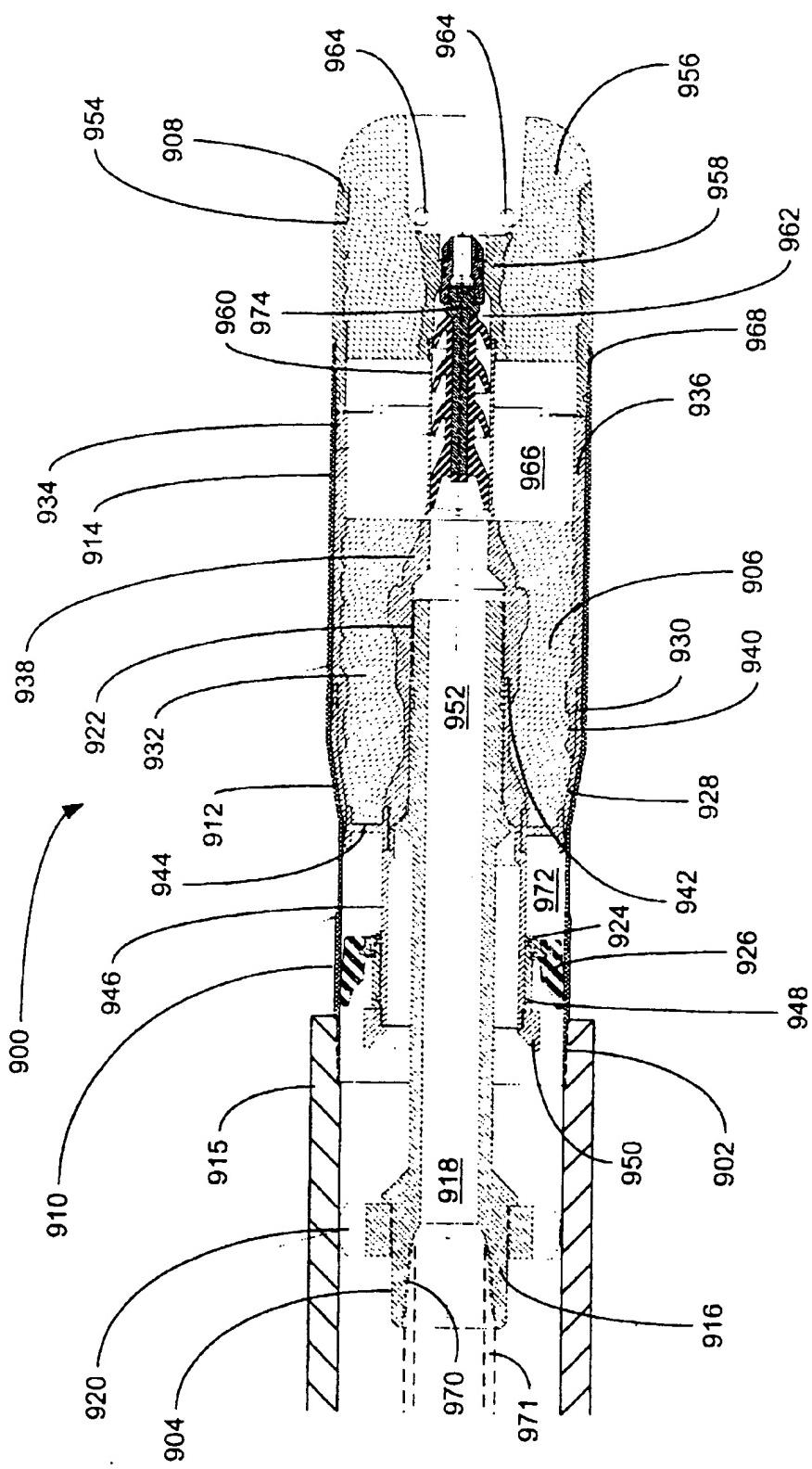


FIGURE 9

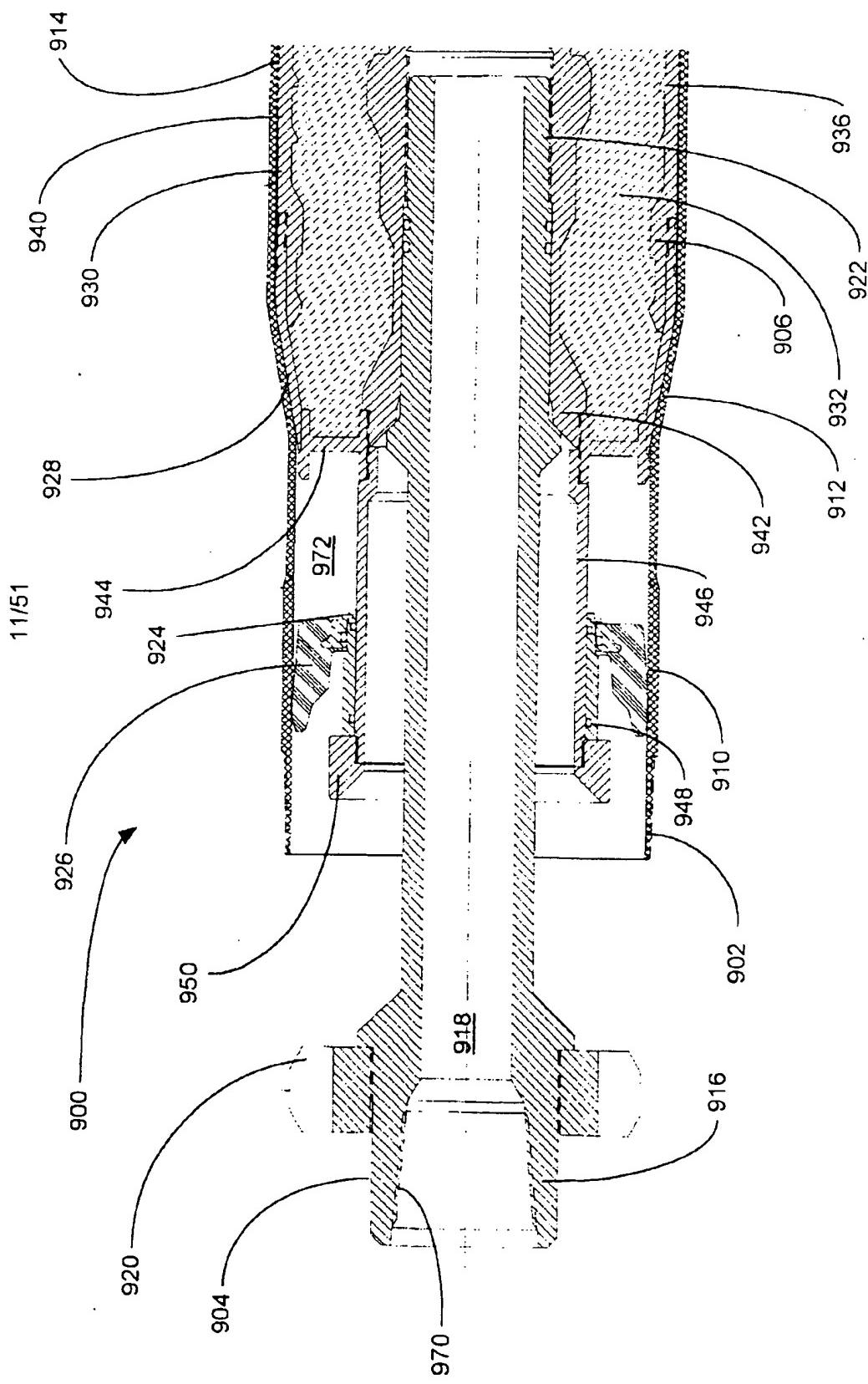


FIGURE 9a

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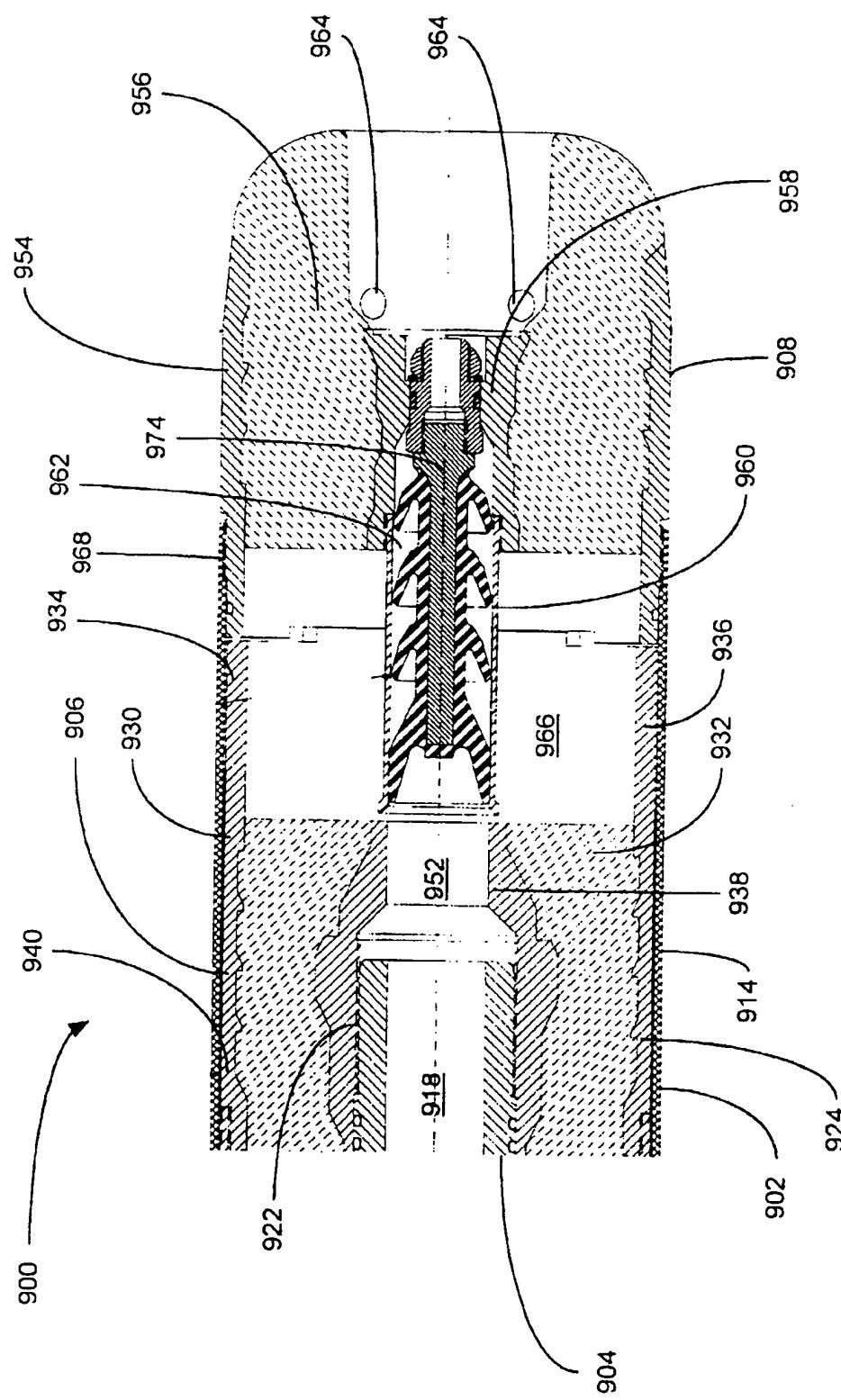


FIGURE 9b

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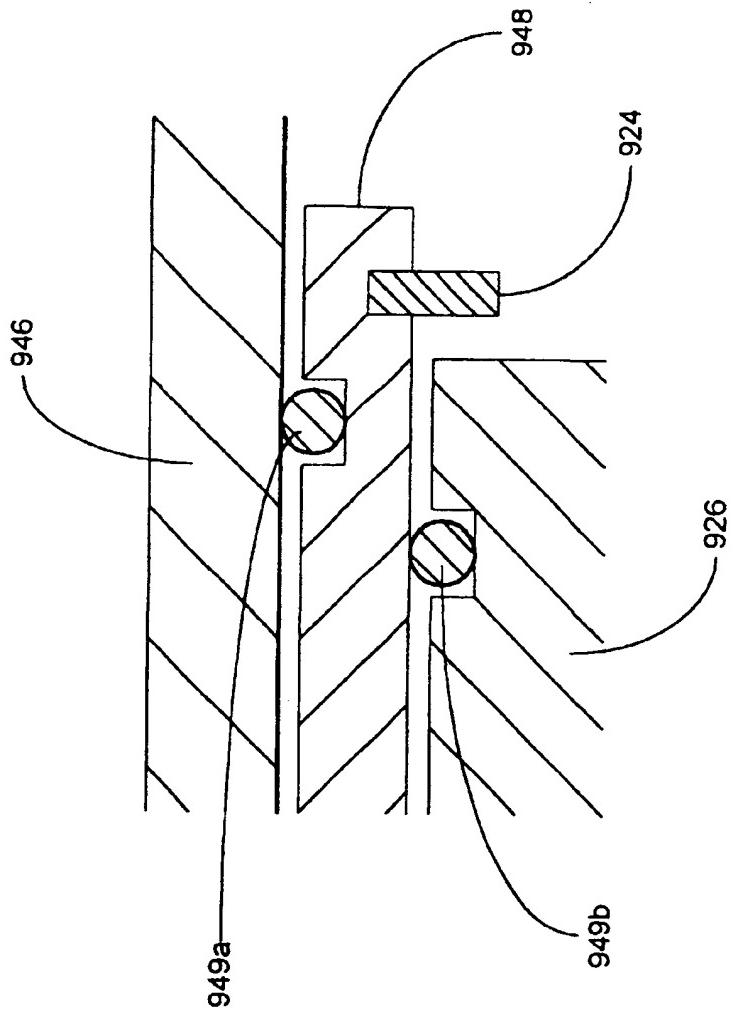
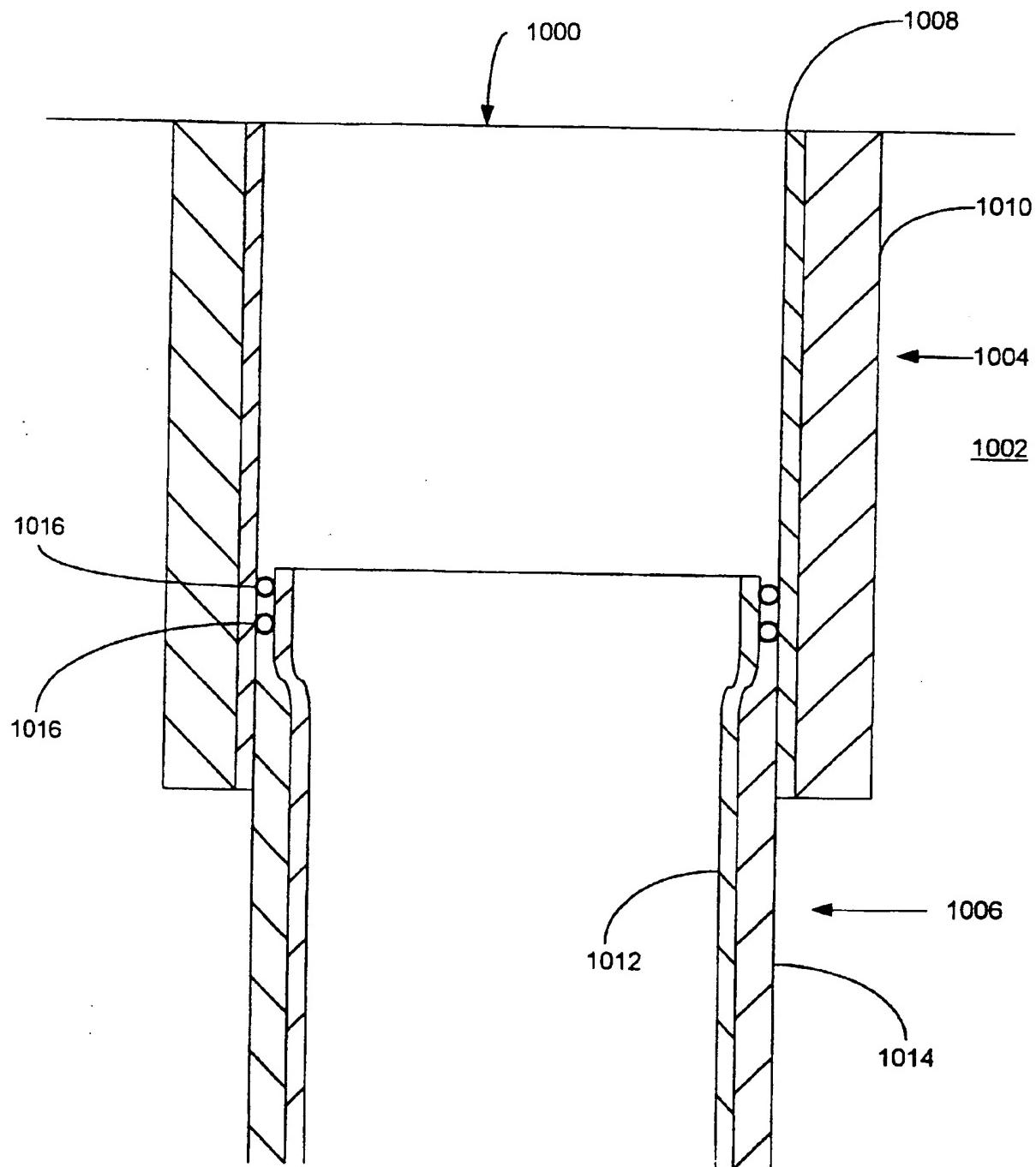


FIGURE 9C

**FIGURE 10a**

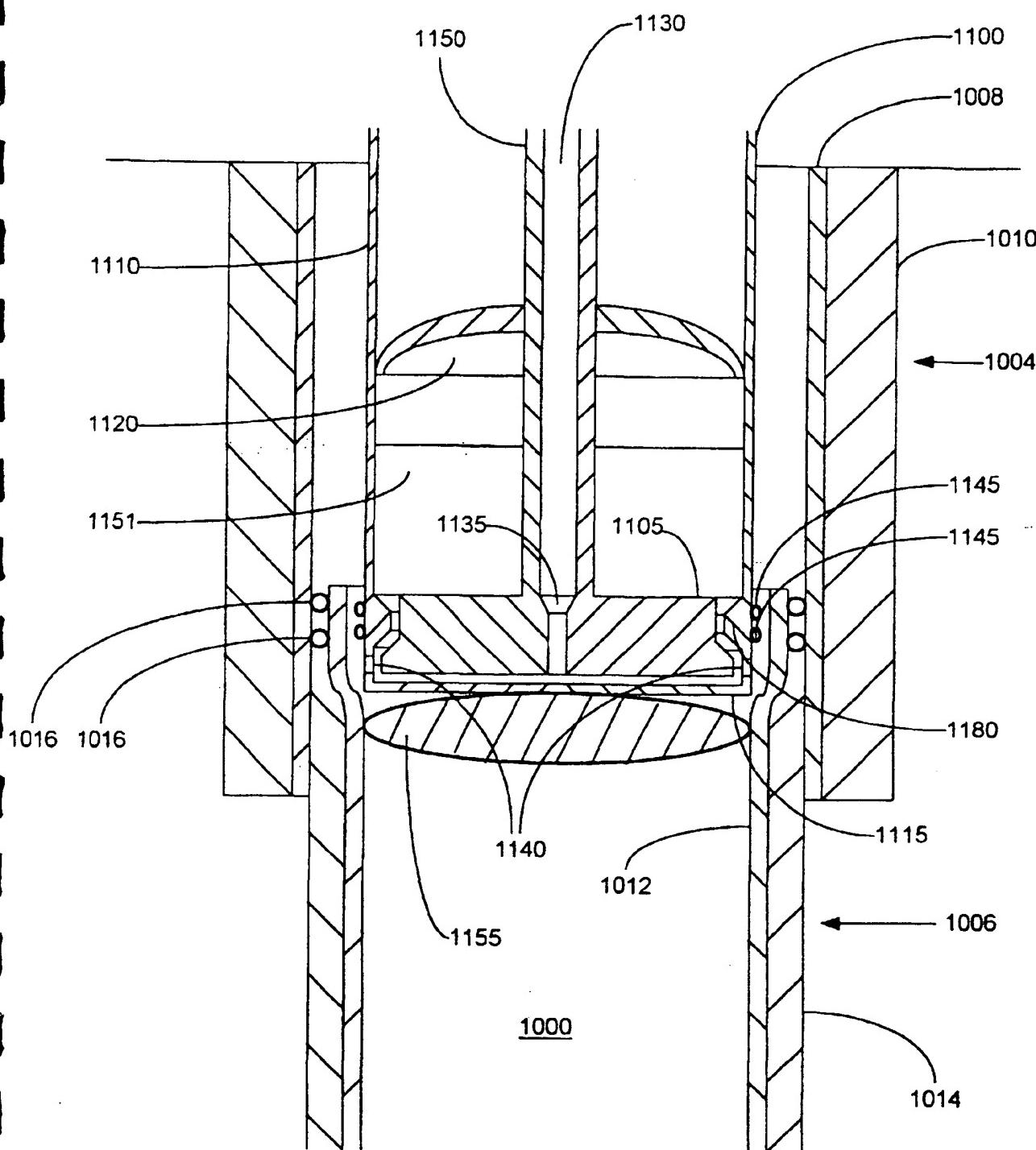
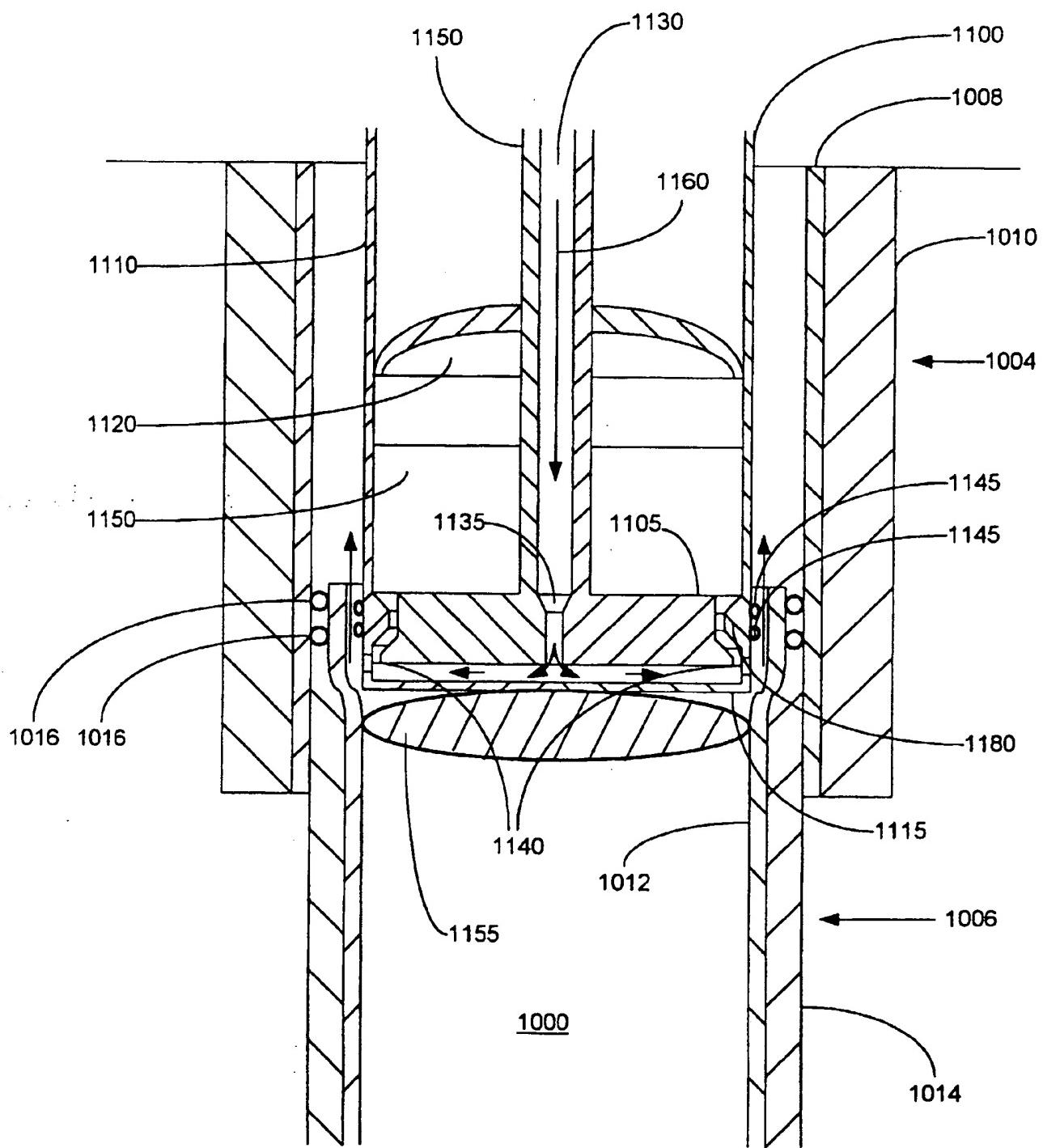


FIGURE 10b

**FIGURE 10c**

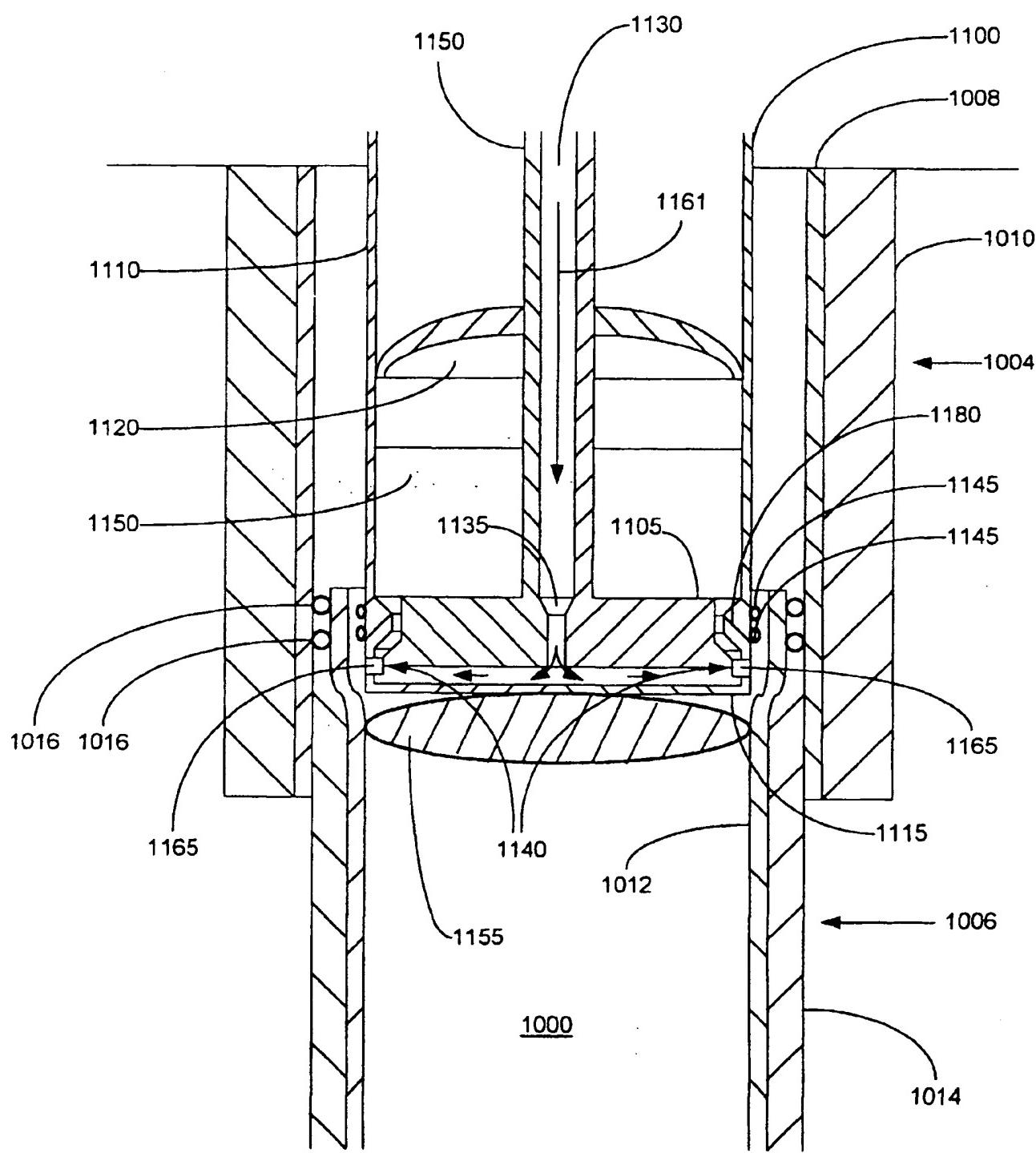
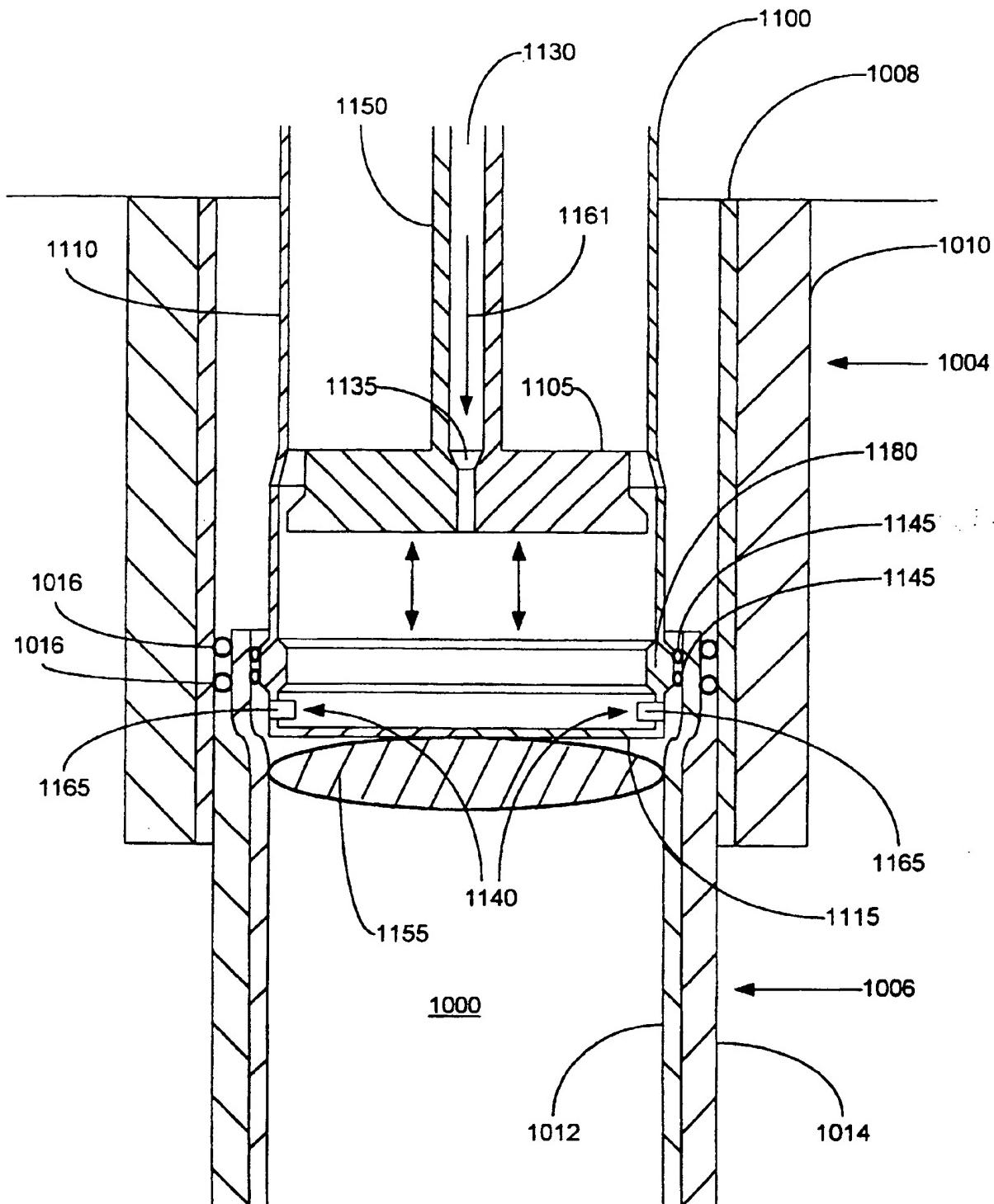


FIGURE 10d

**FIGURE 10e**

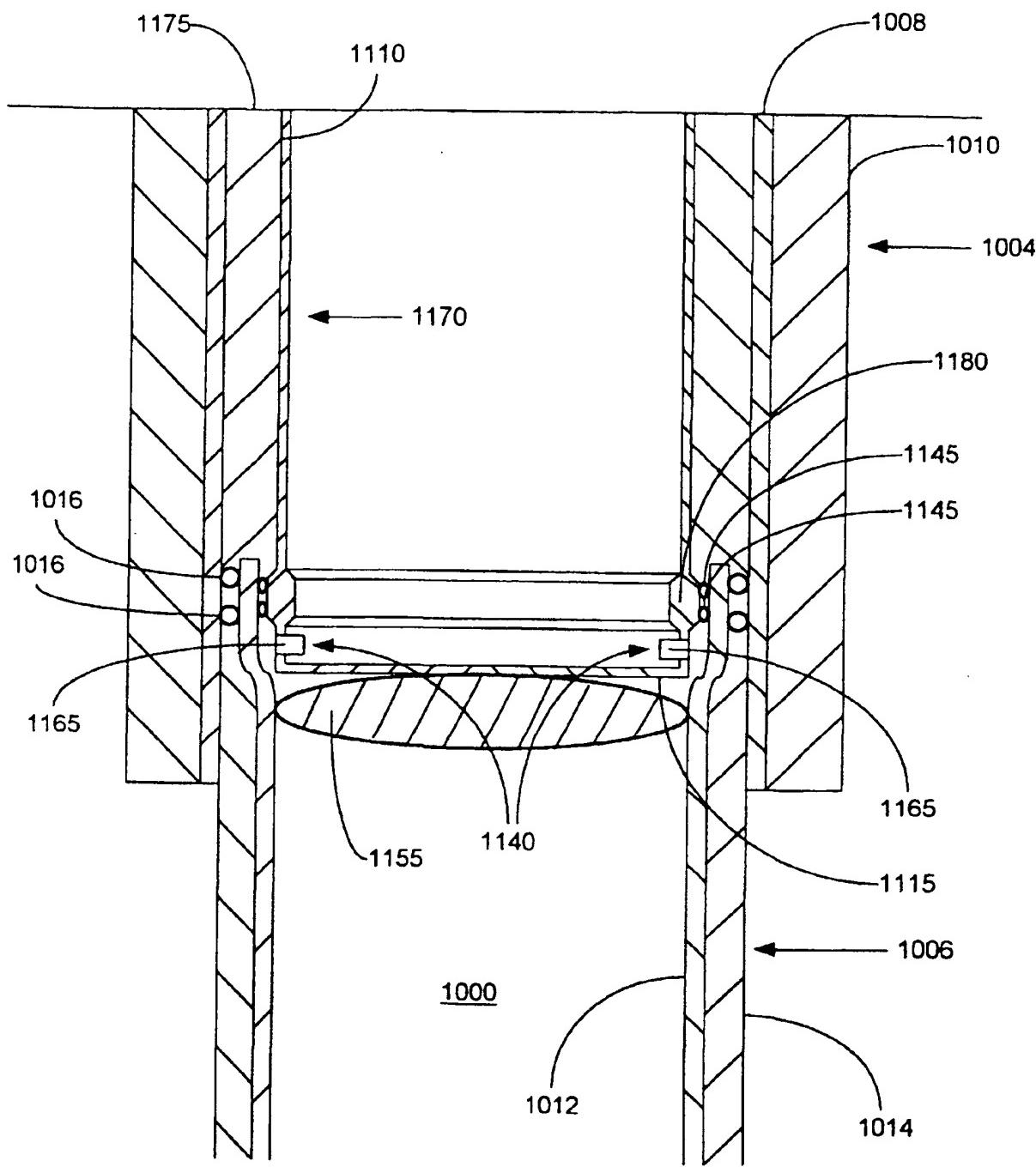


FIGURE 10f

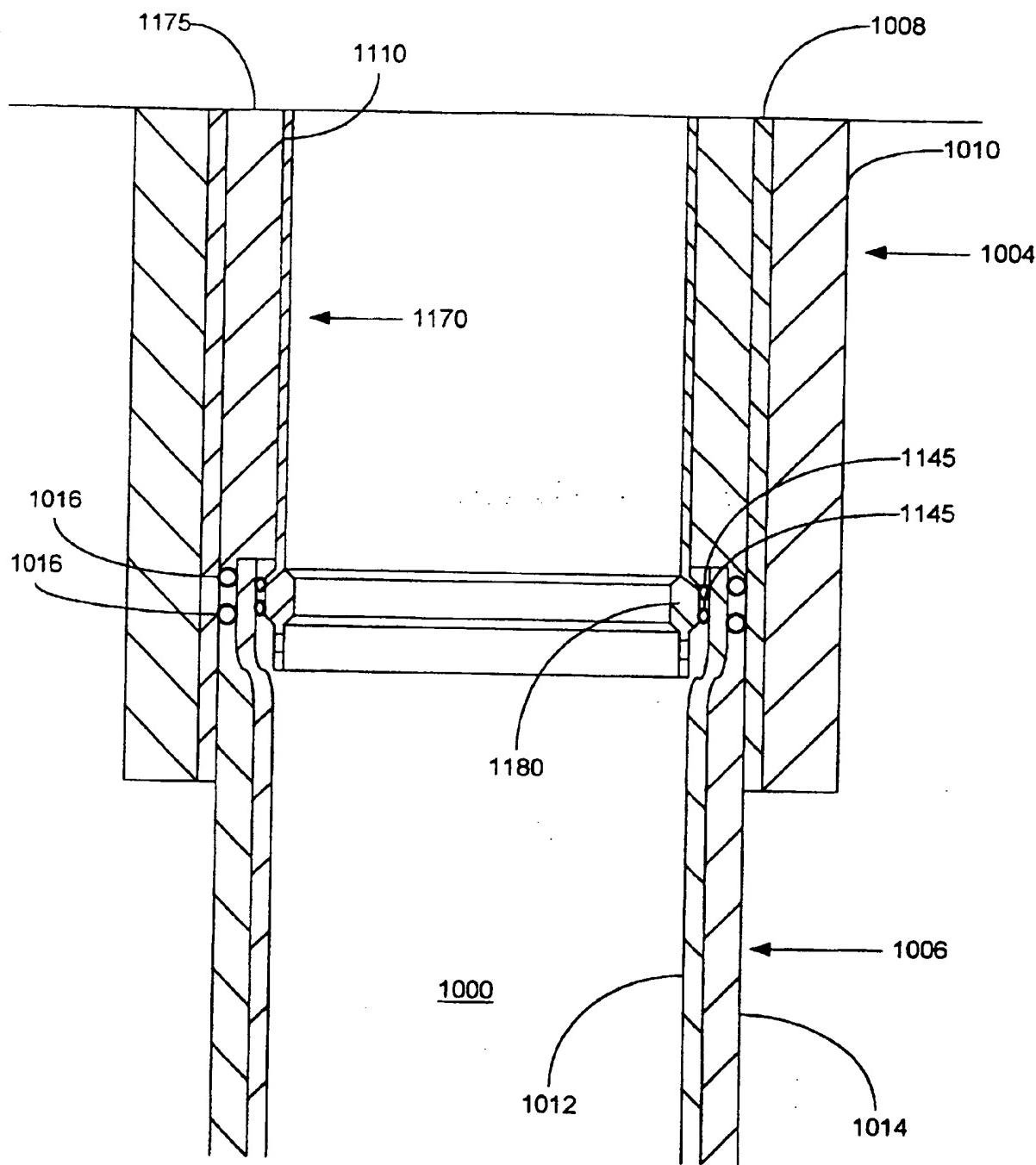


FIGURE 10g

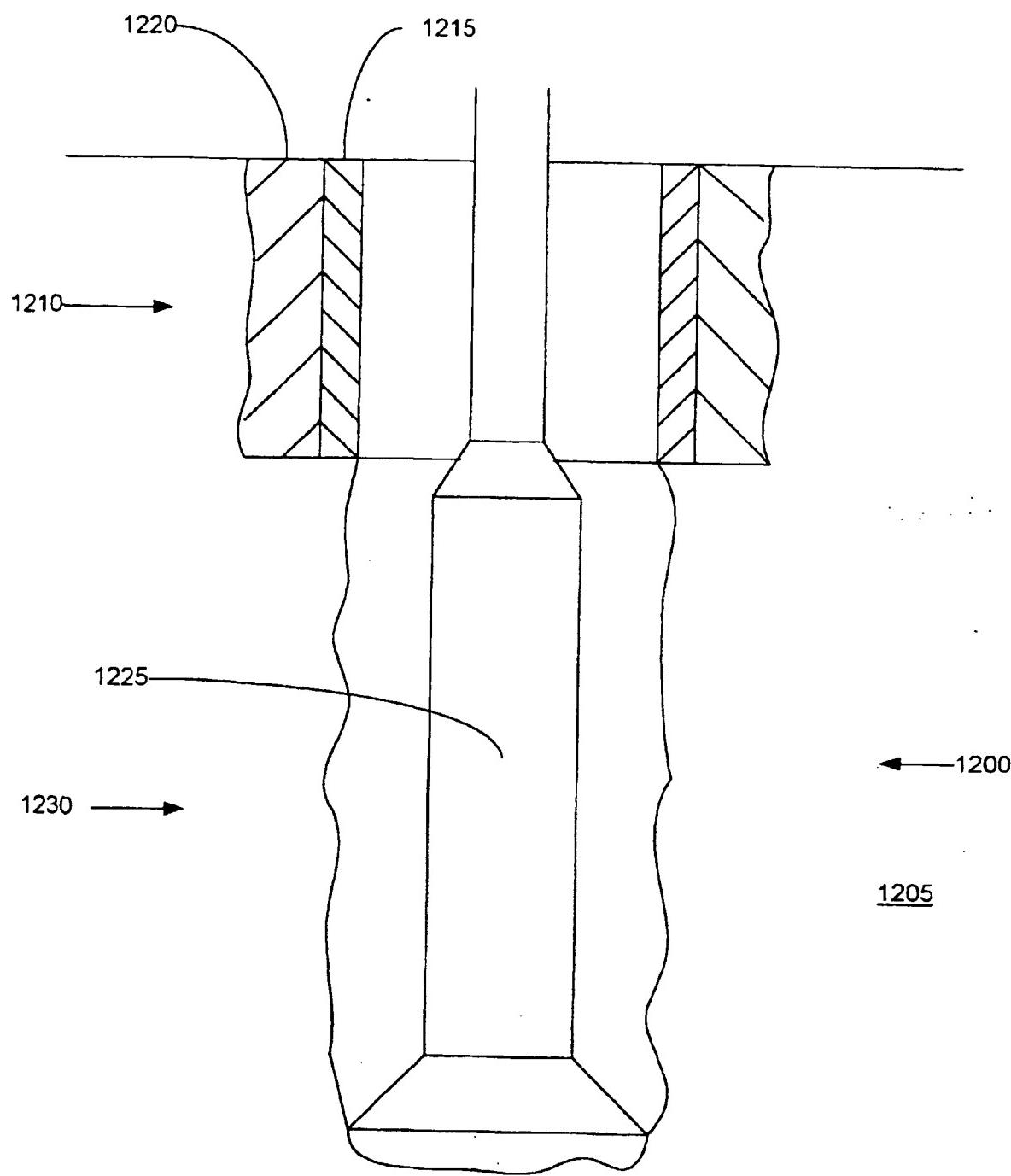


FIGURE 11a

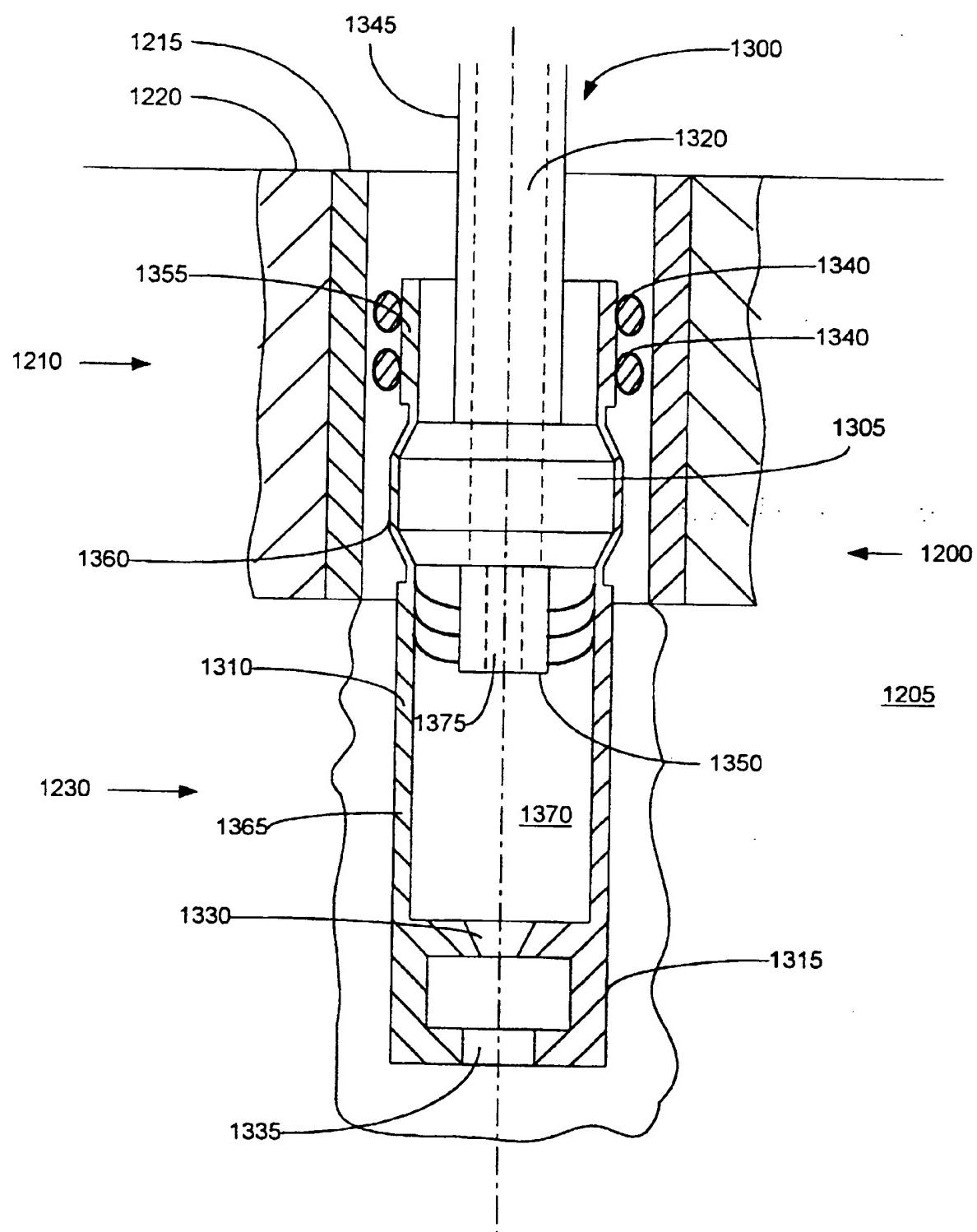
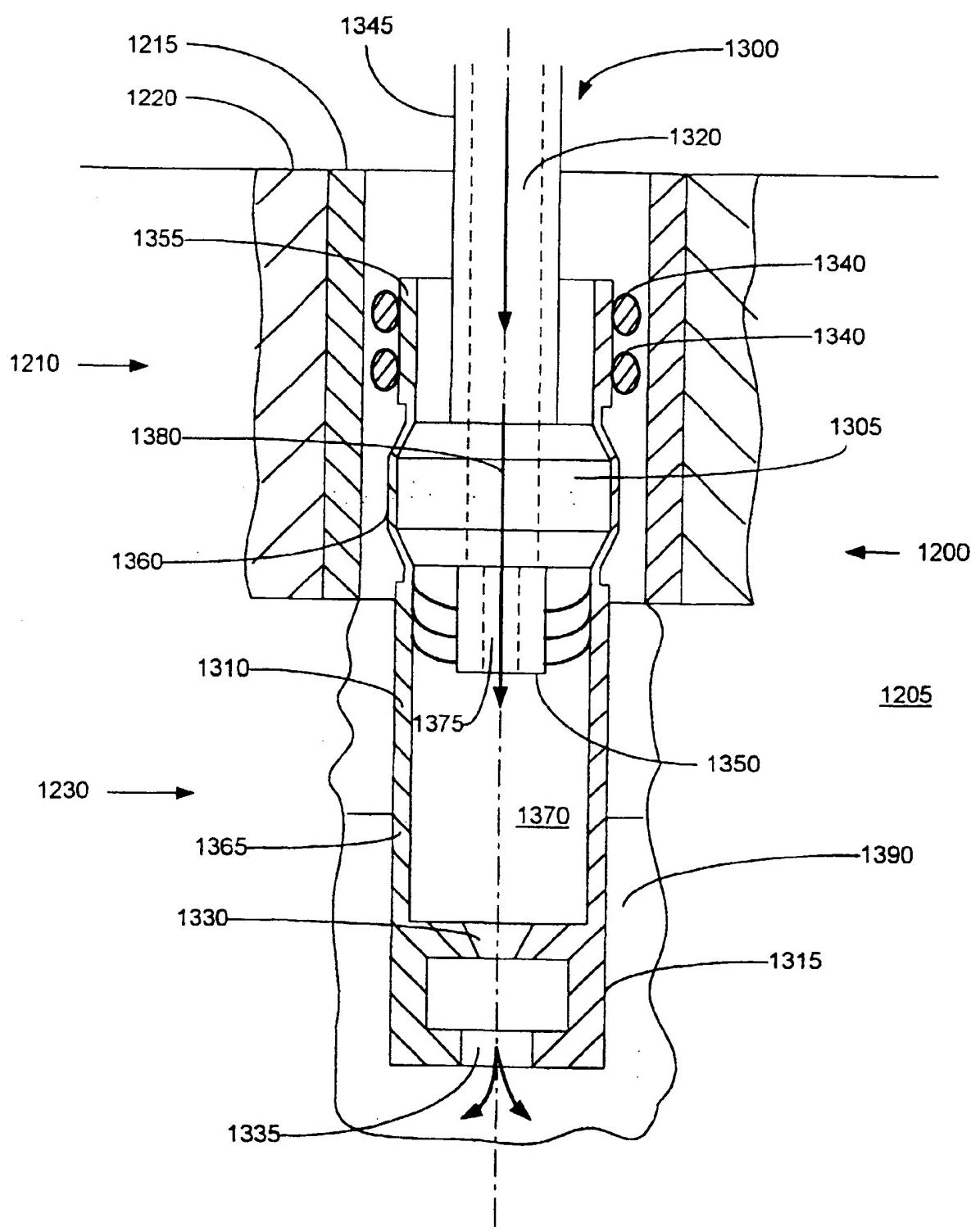


FIGURE 11b

**FIGURE 11c**

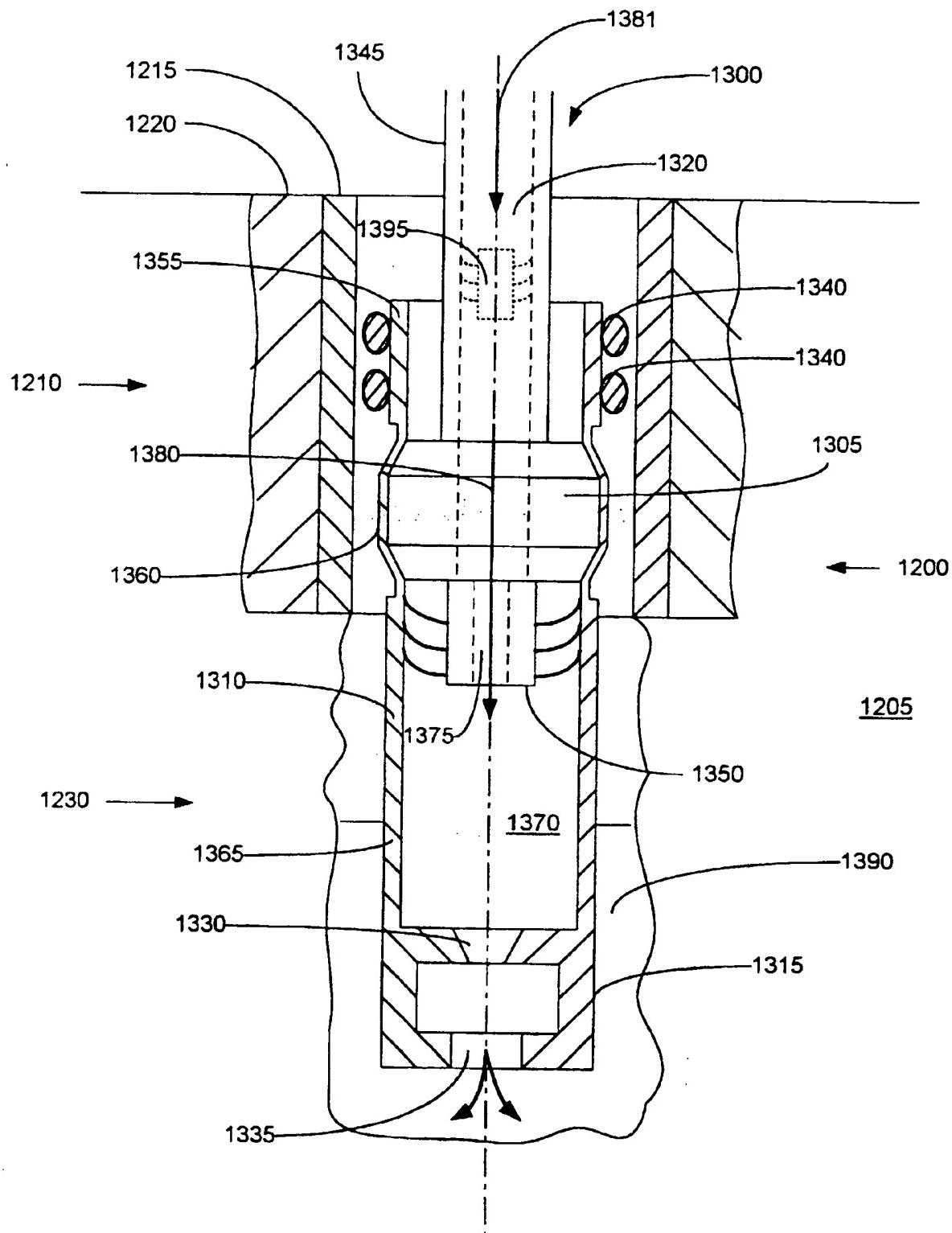


FIGURE 11d

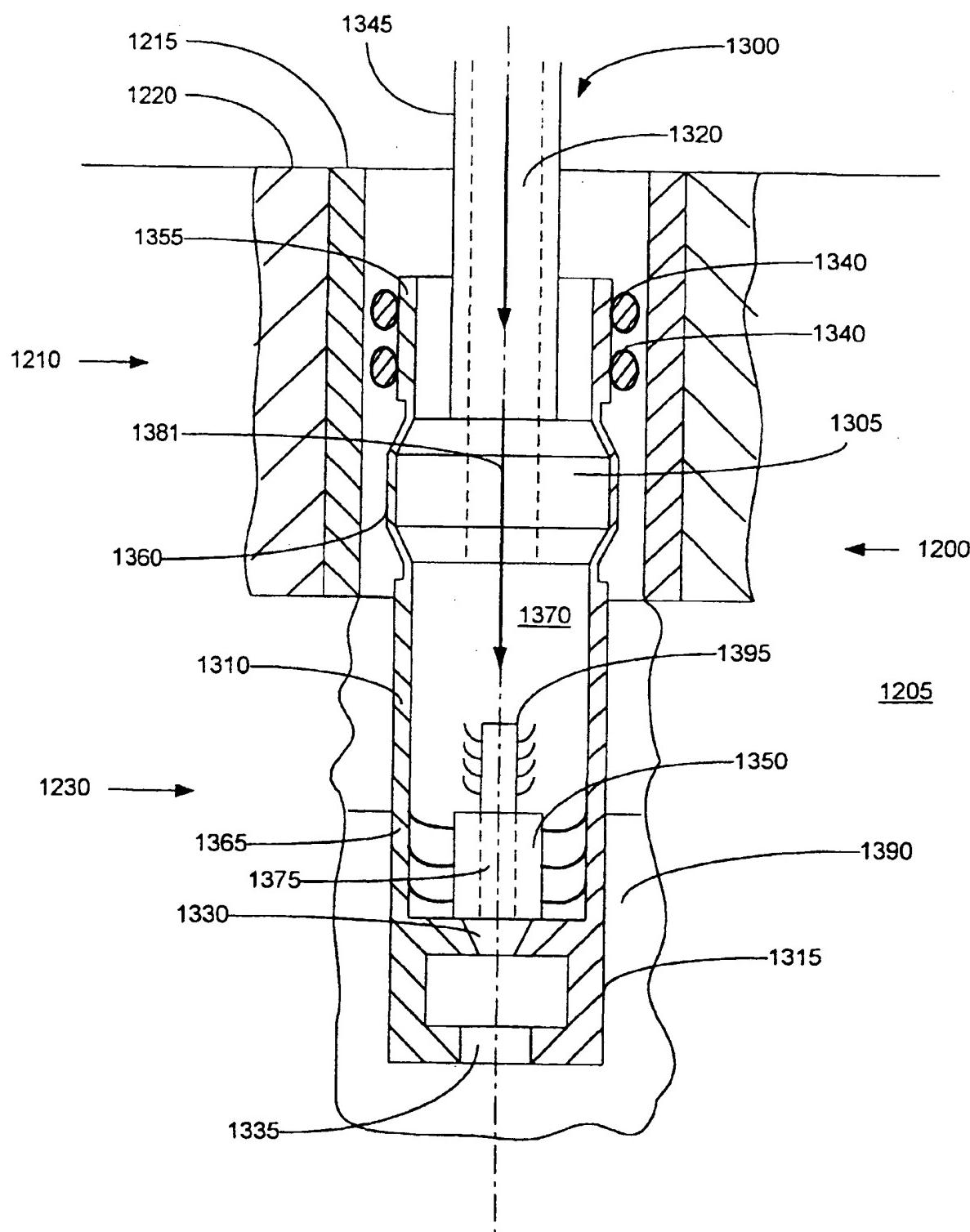


FIGURE 11e

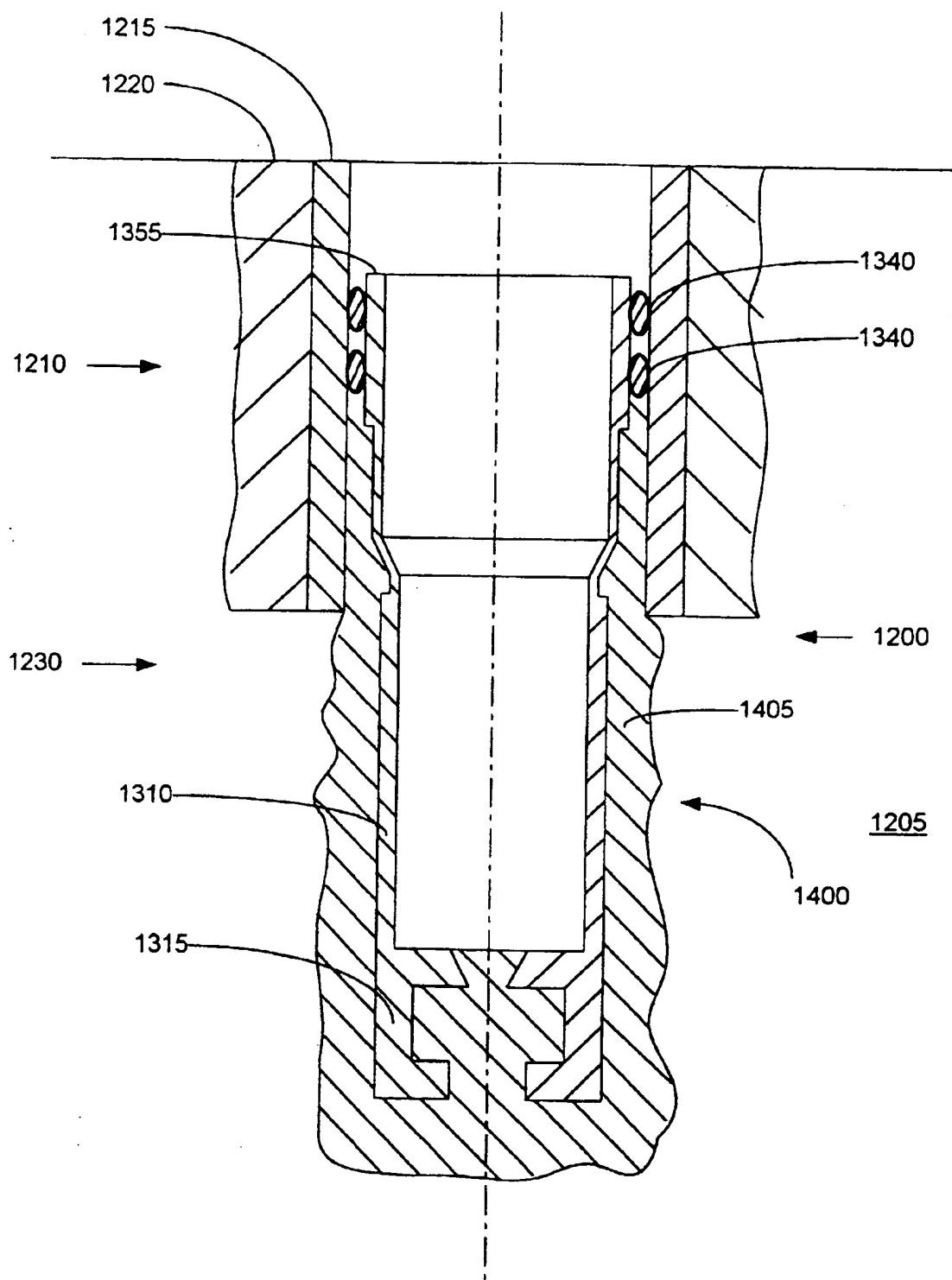
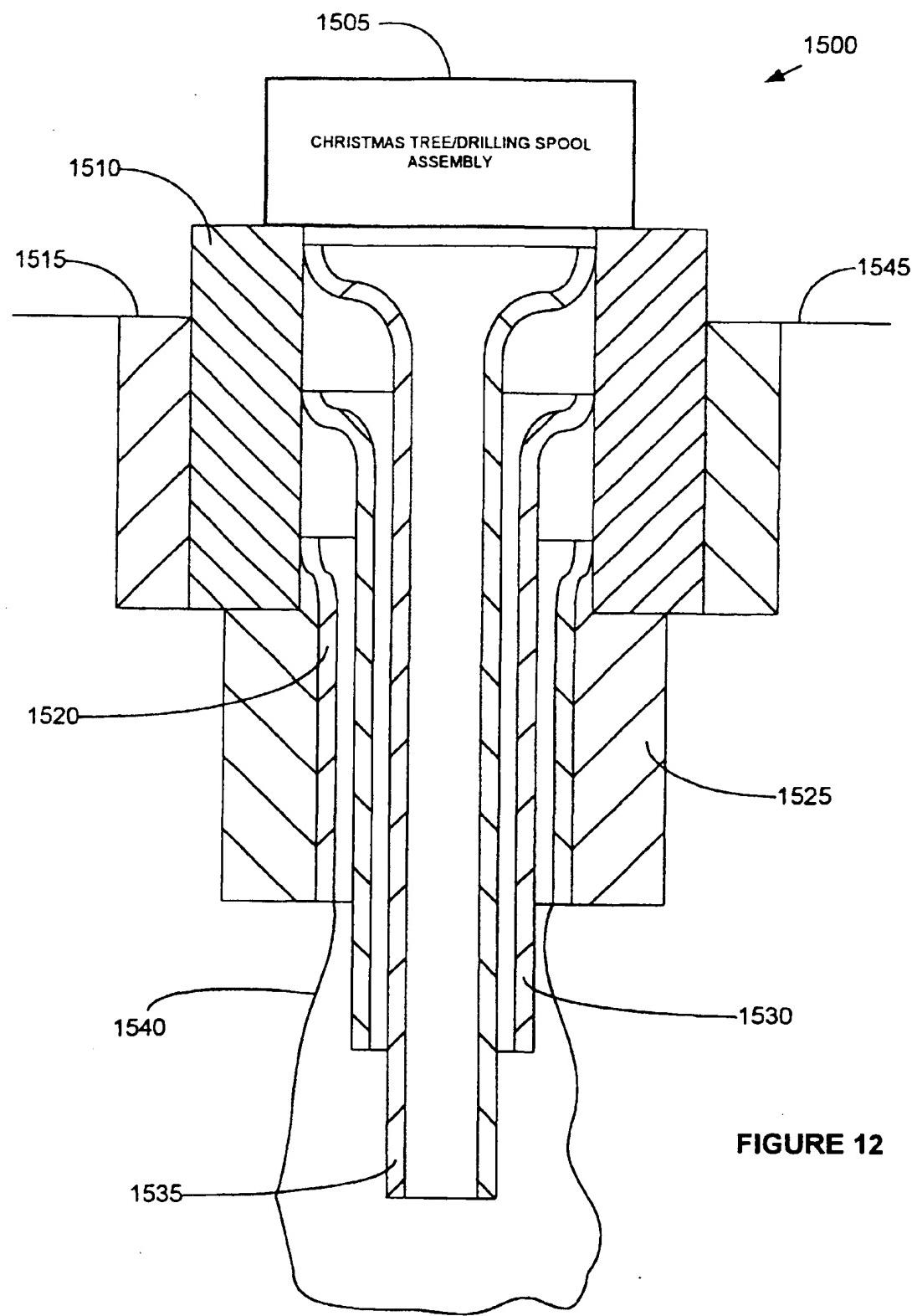


FIGURE 11f

**FIGURE 12**

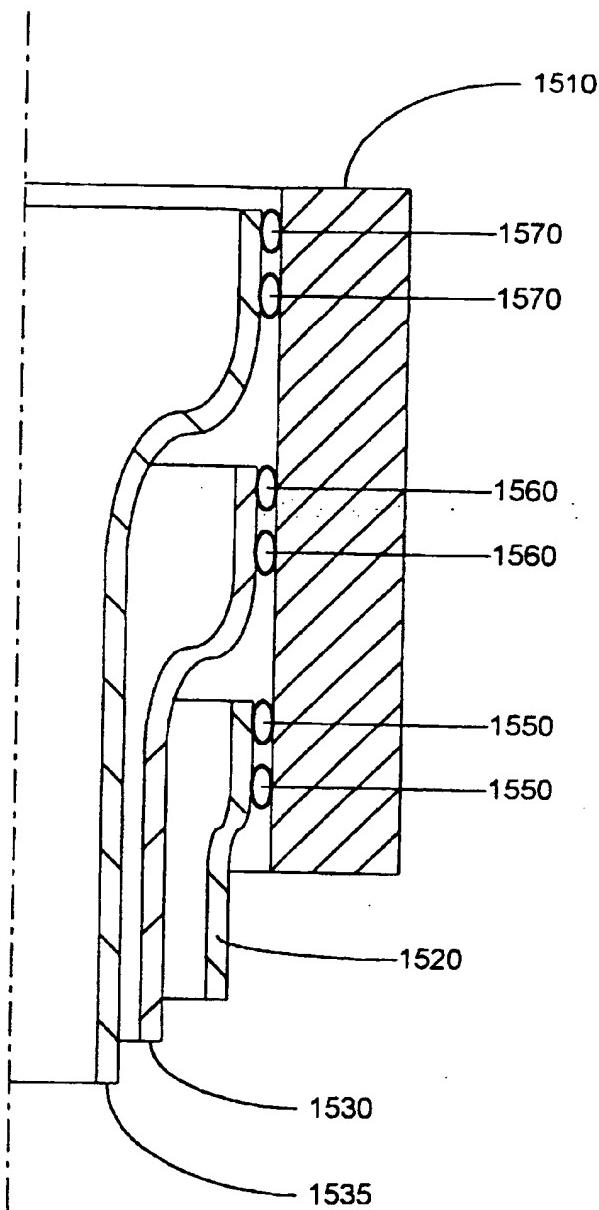


FIGURE 13

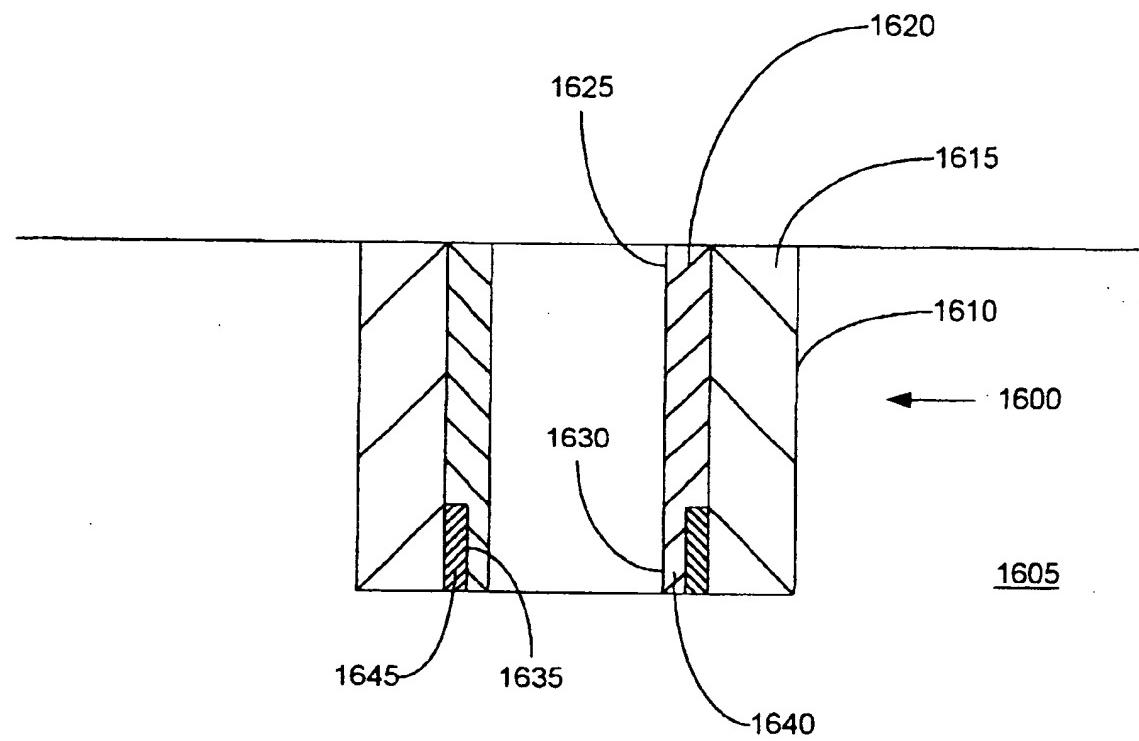


FIGURE 14a

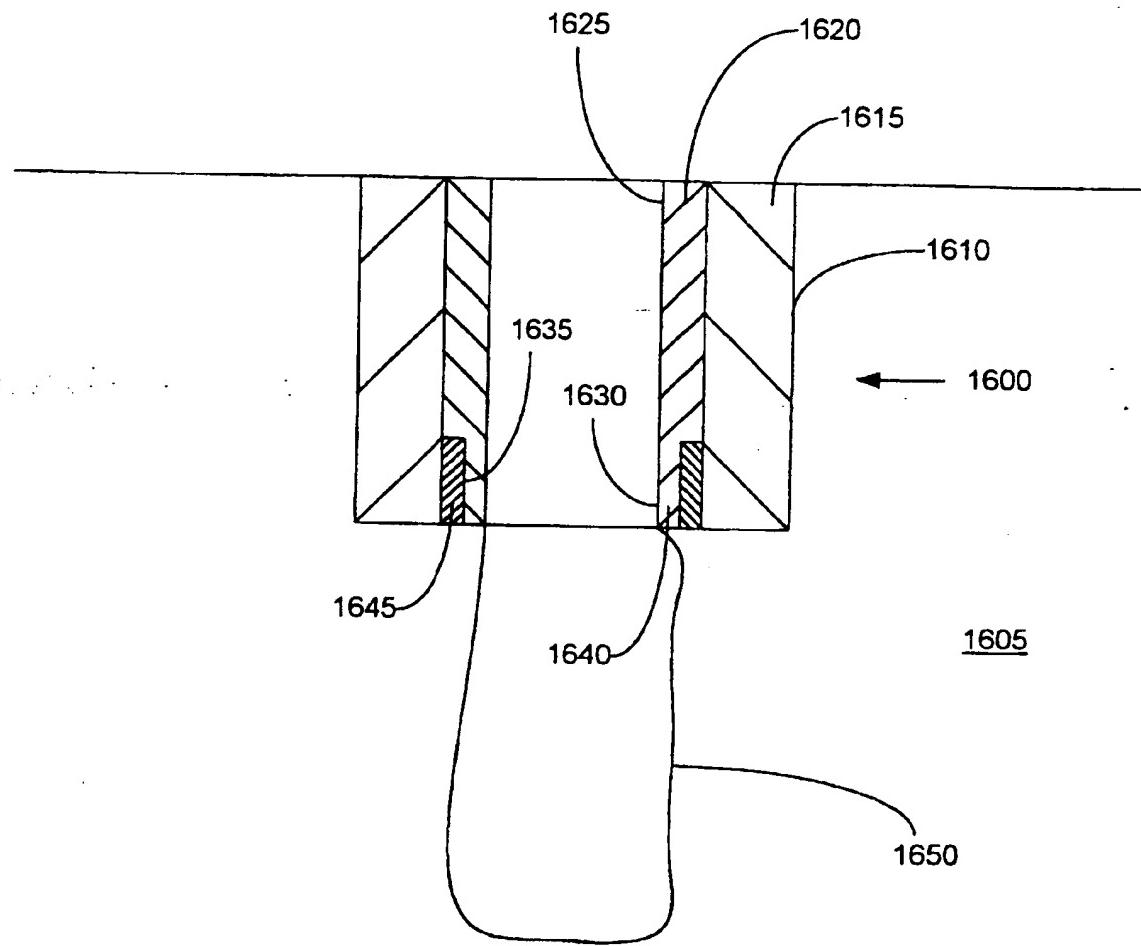
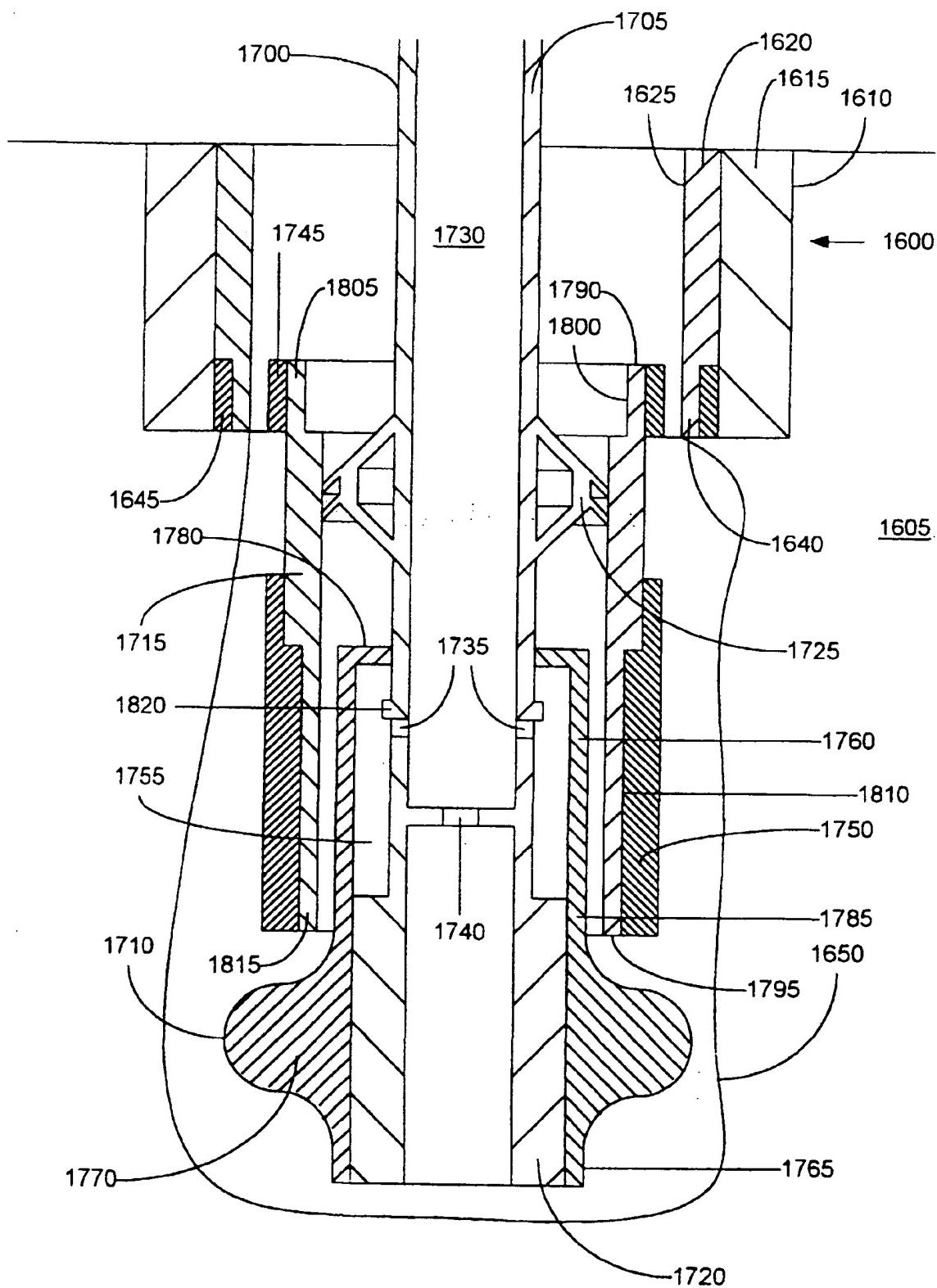
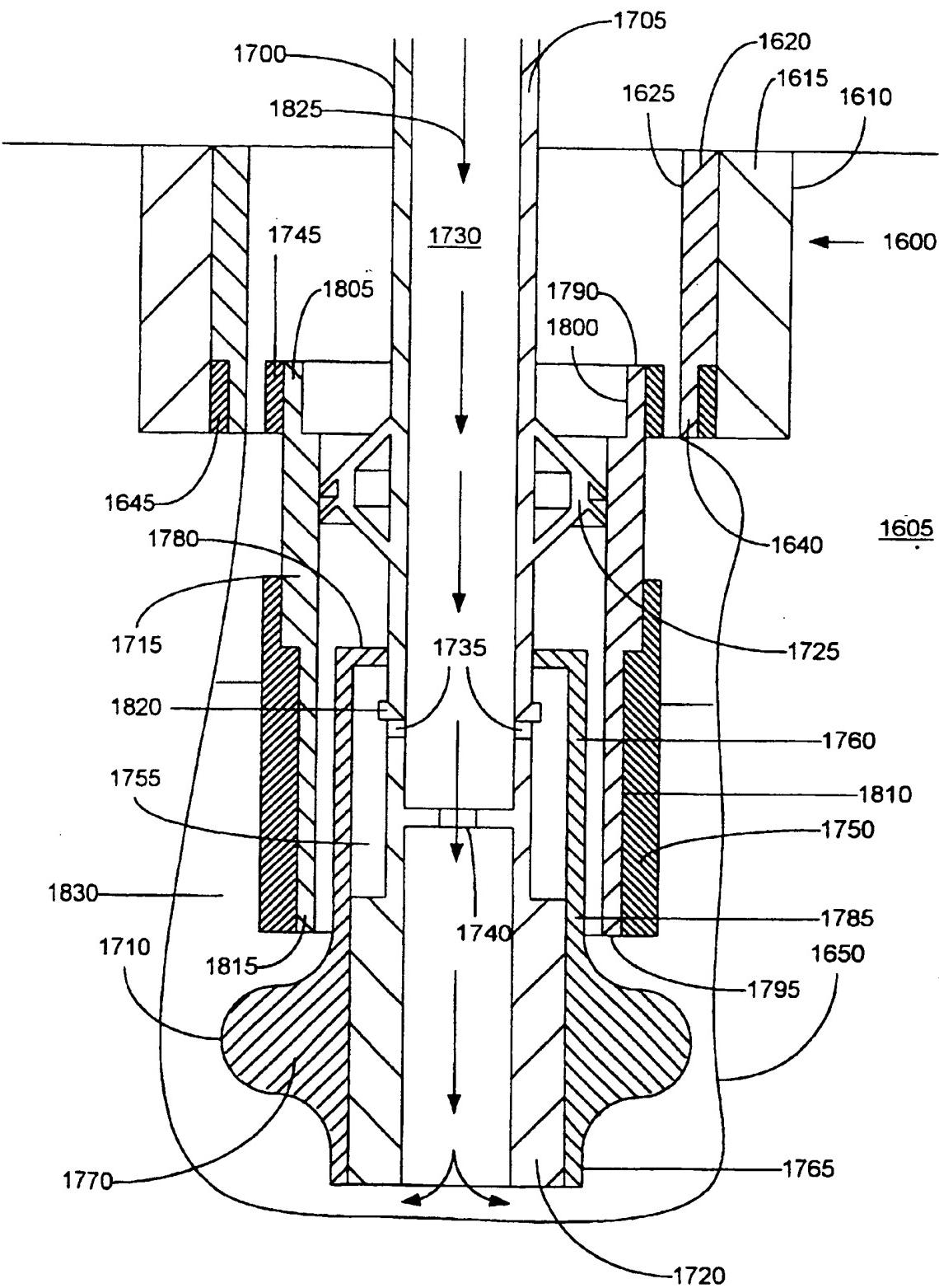


FIGURE 14b

**FIGURE 14c**

**FIGURE 14d**

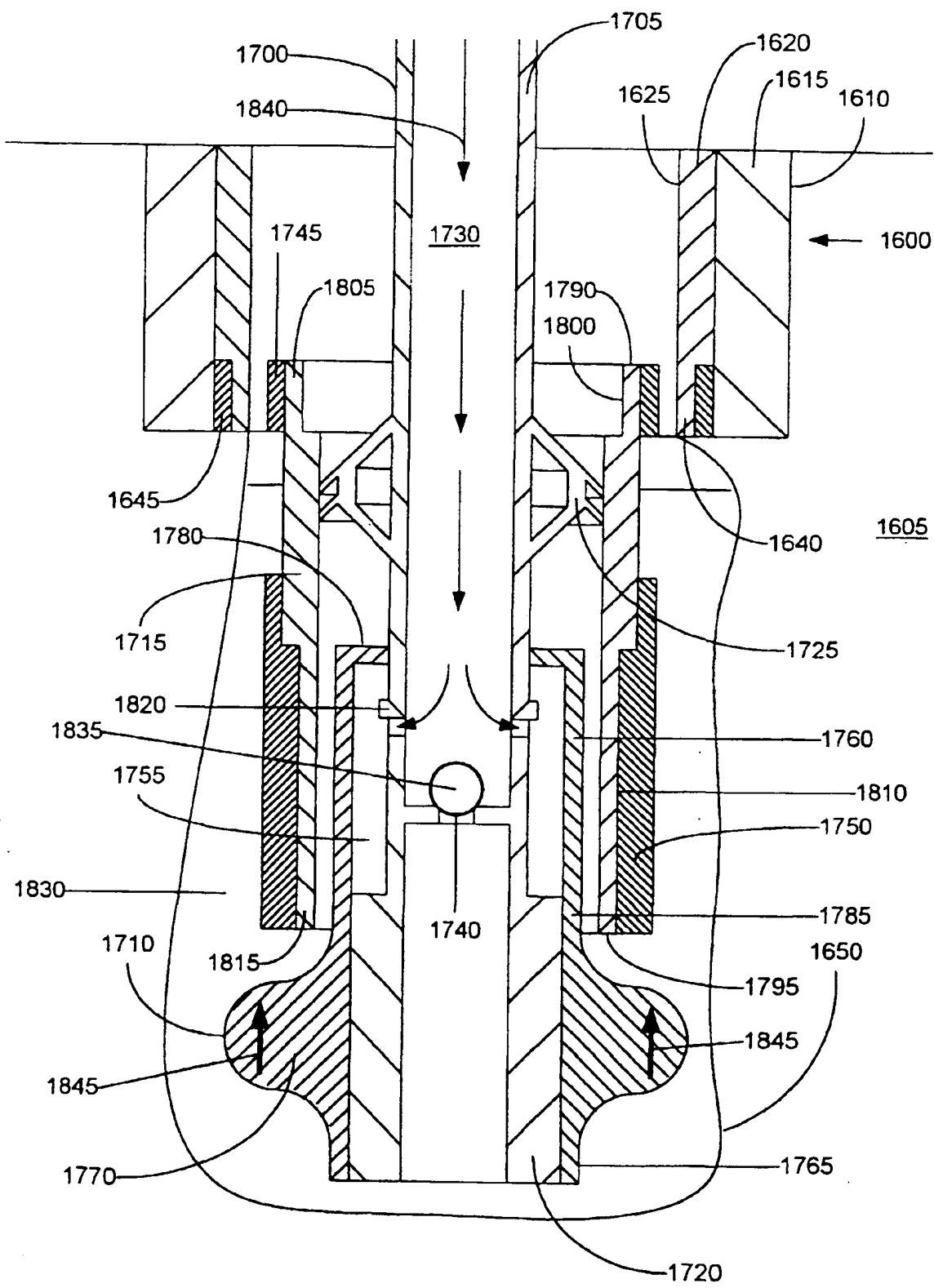
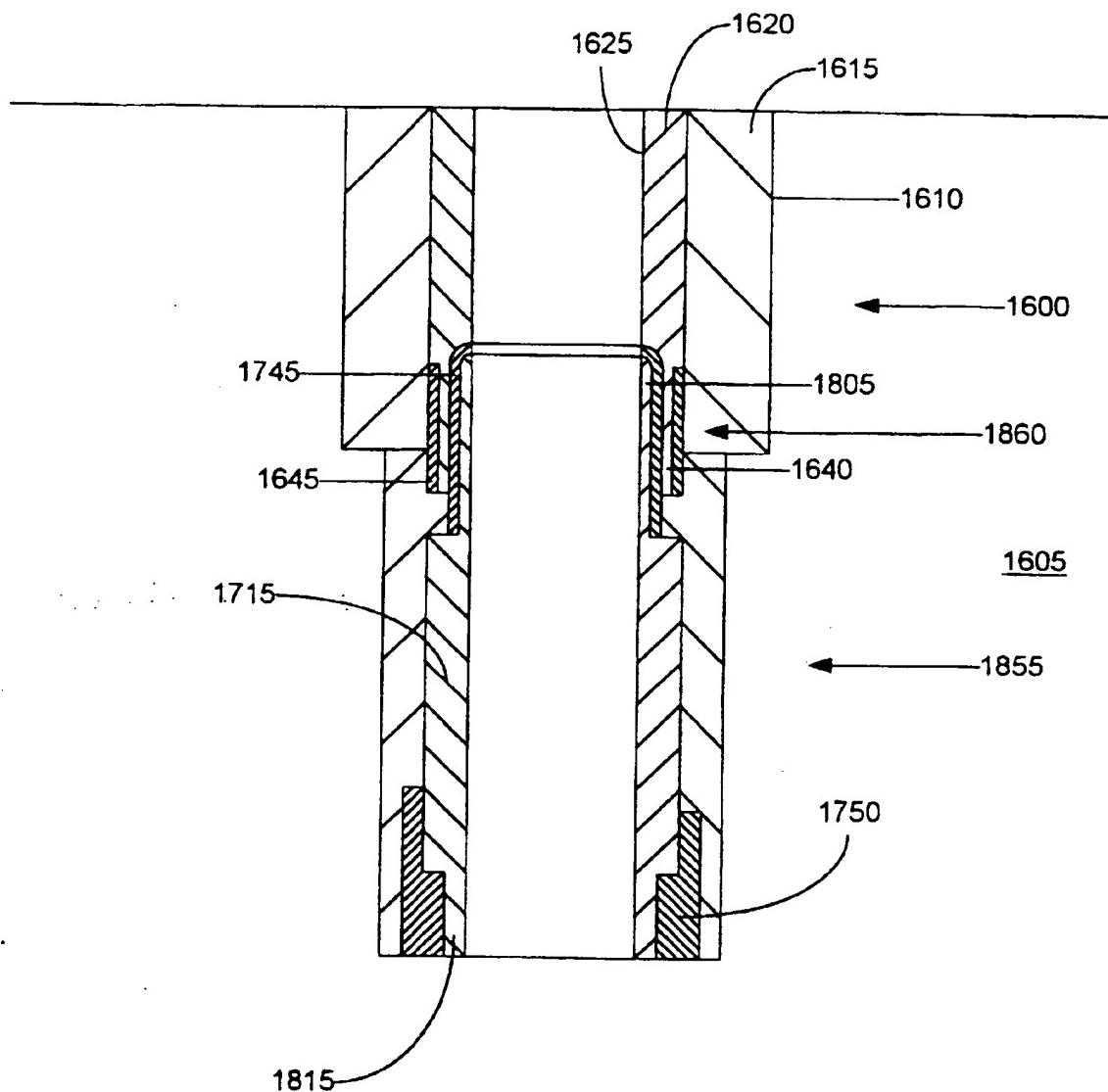


FIGURE 14e

**FIGURE 14f**

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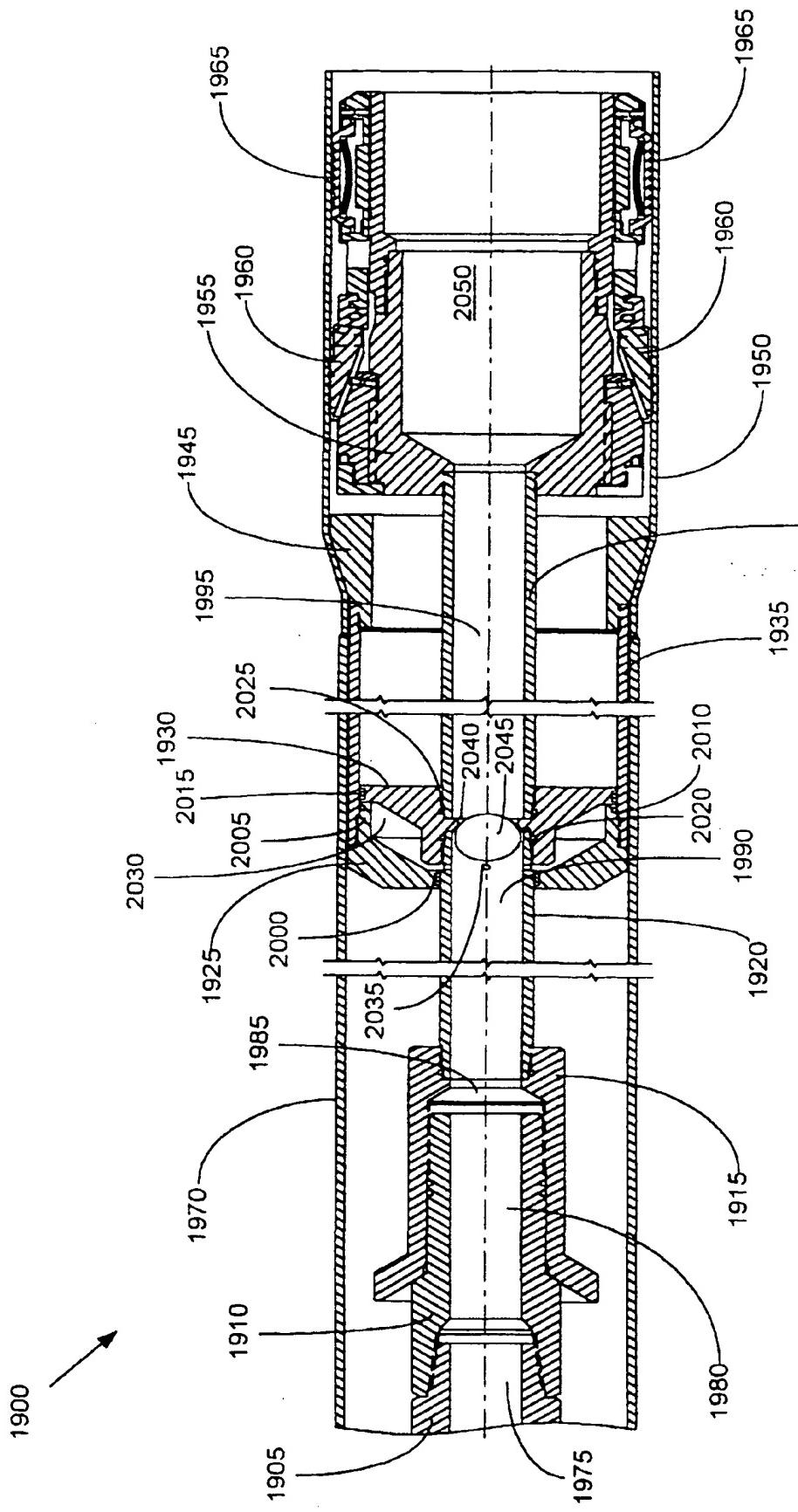


FIGURE 15

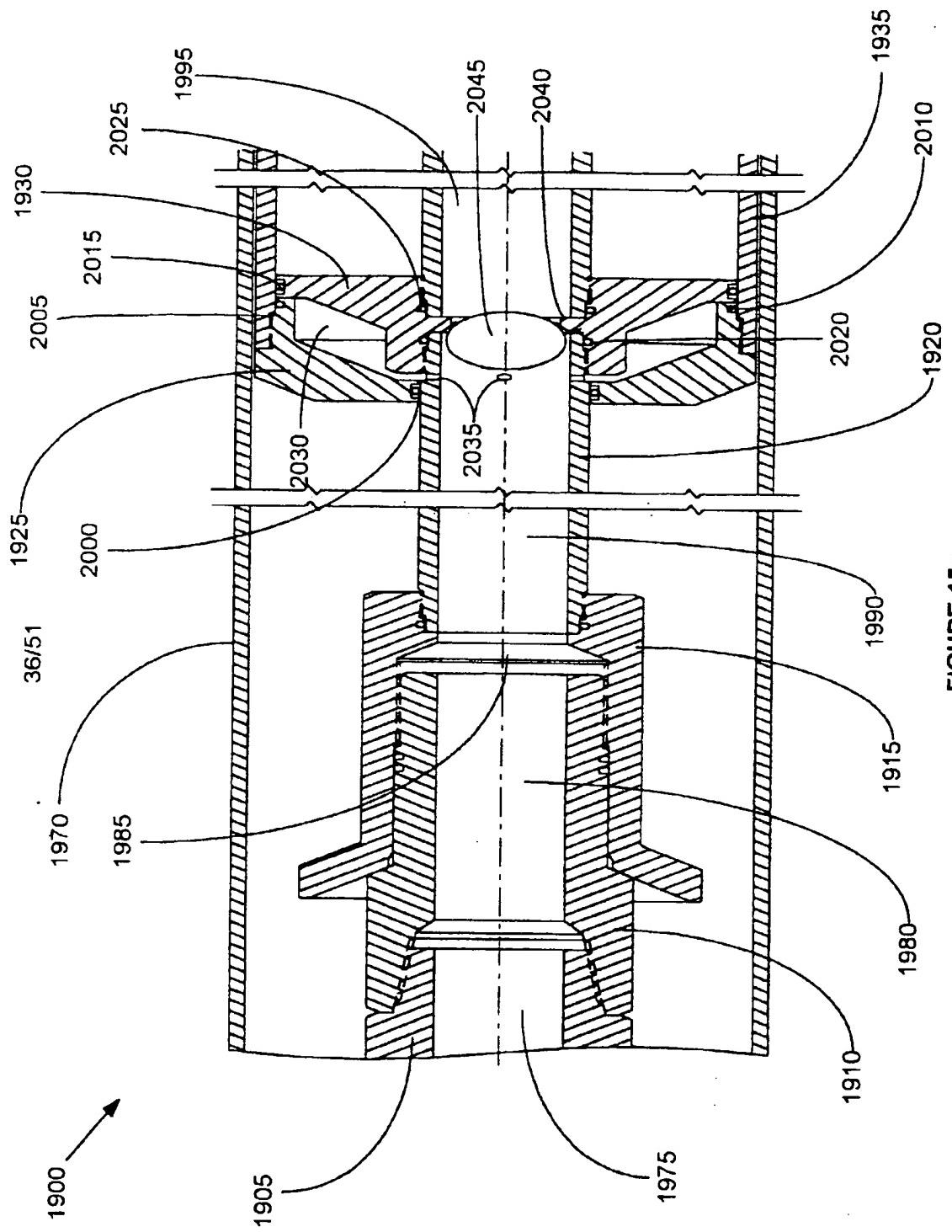


FIGURE 15a

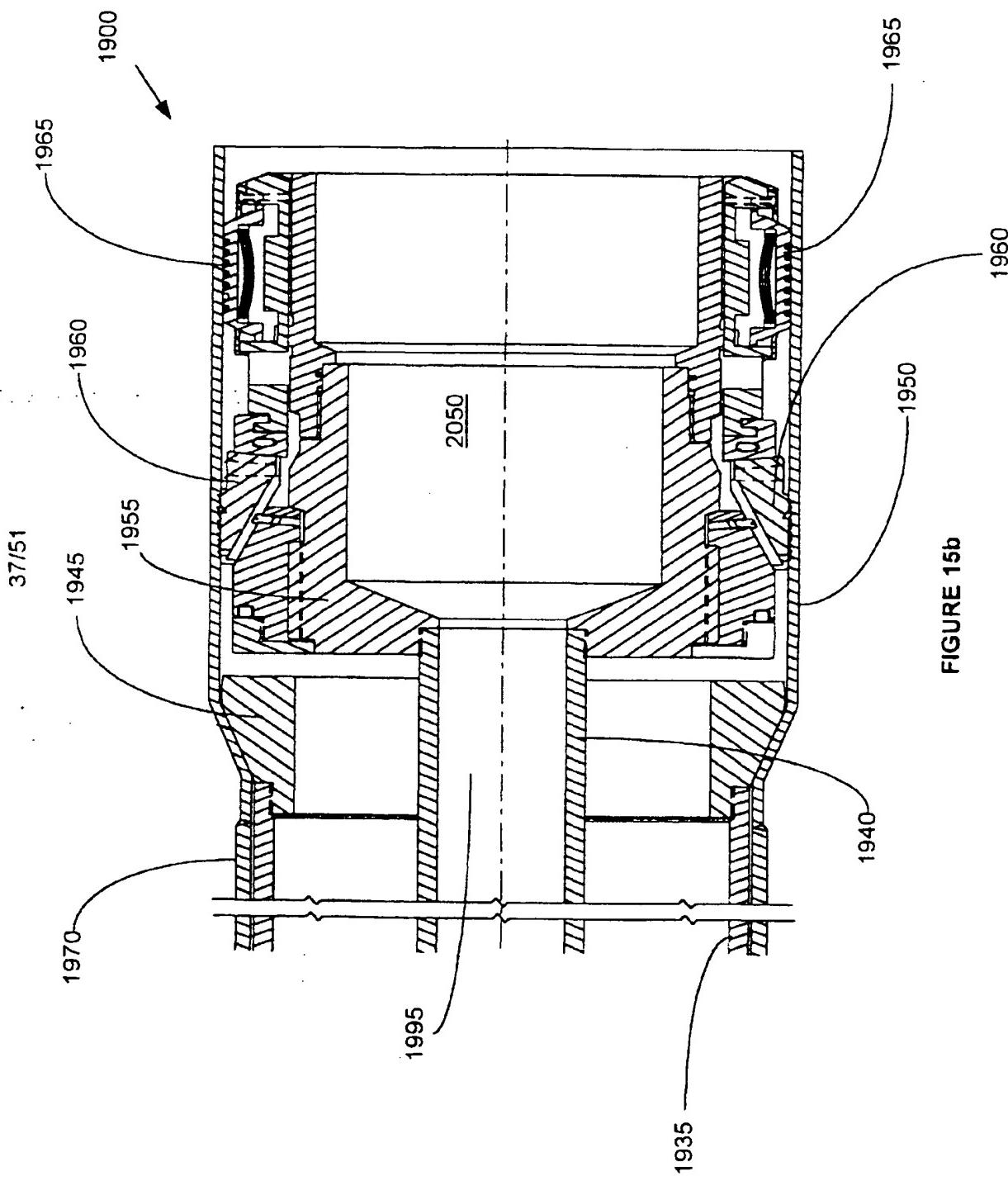


FIGURE 15b

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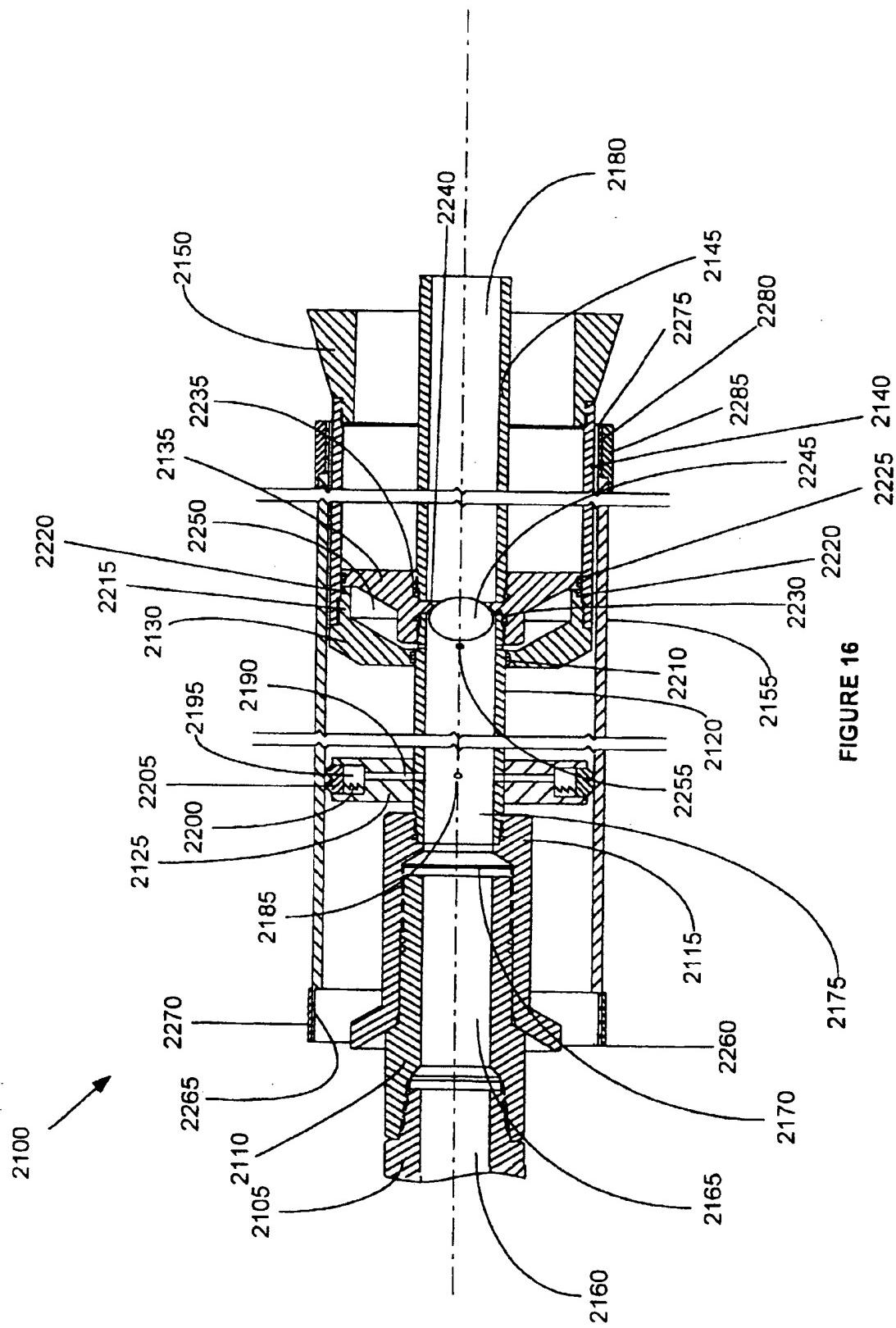


FIGURE 16

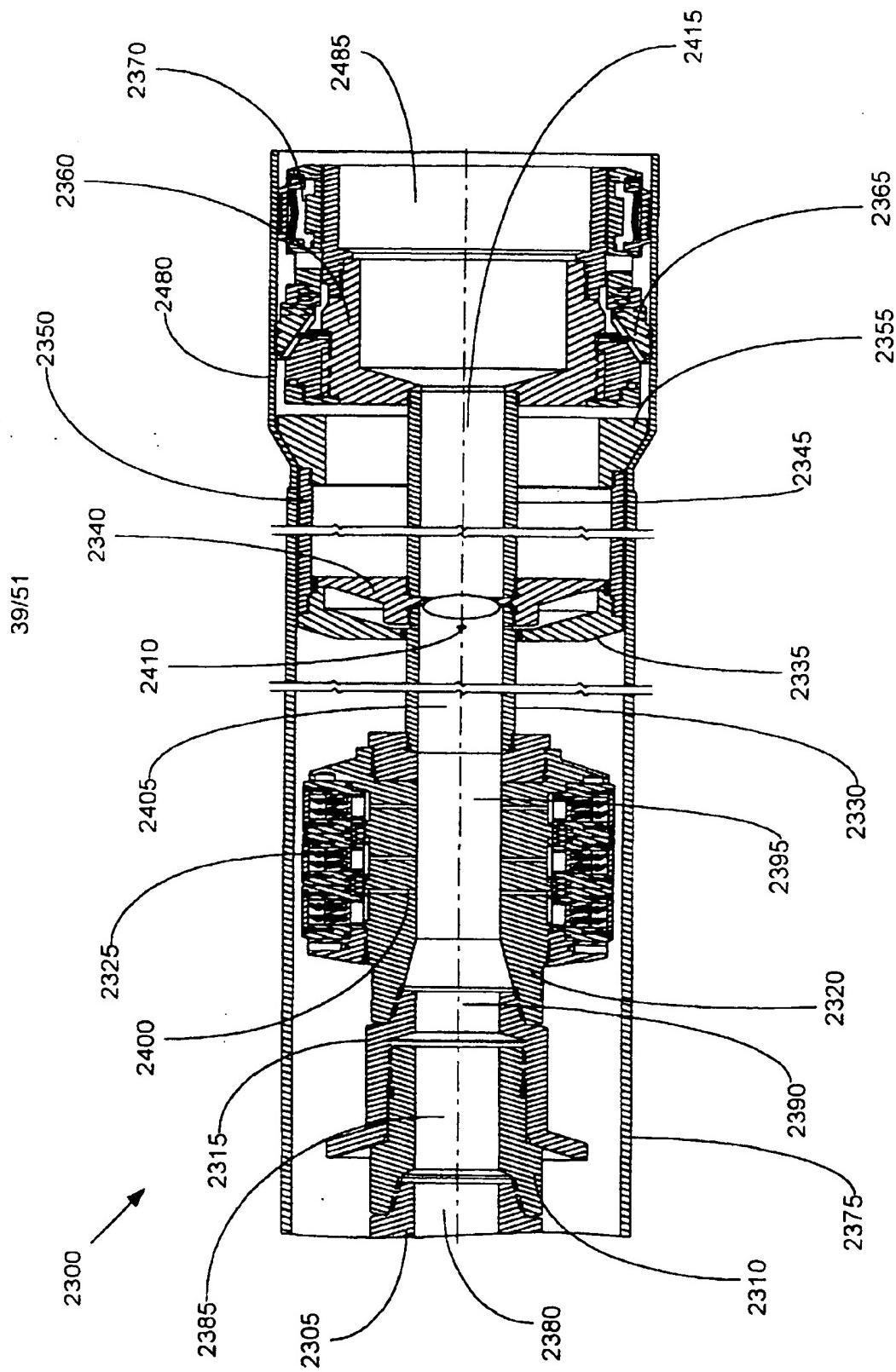


FIGURE 17

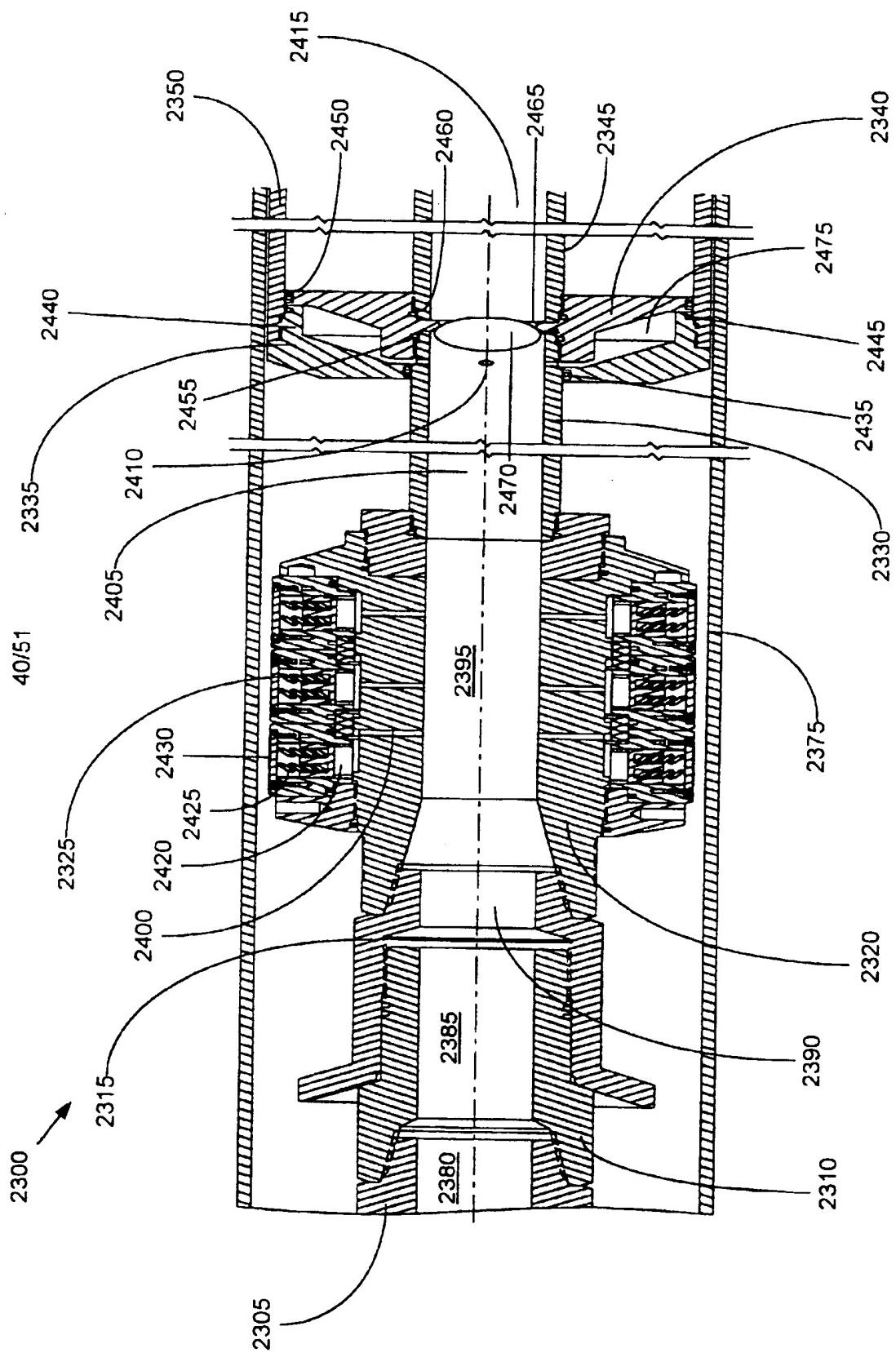


FIGURE 17a

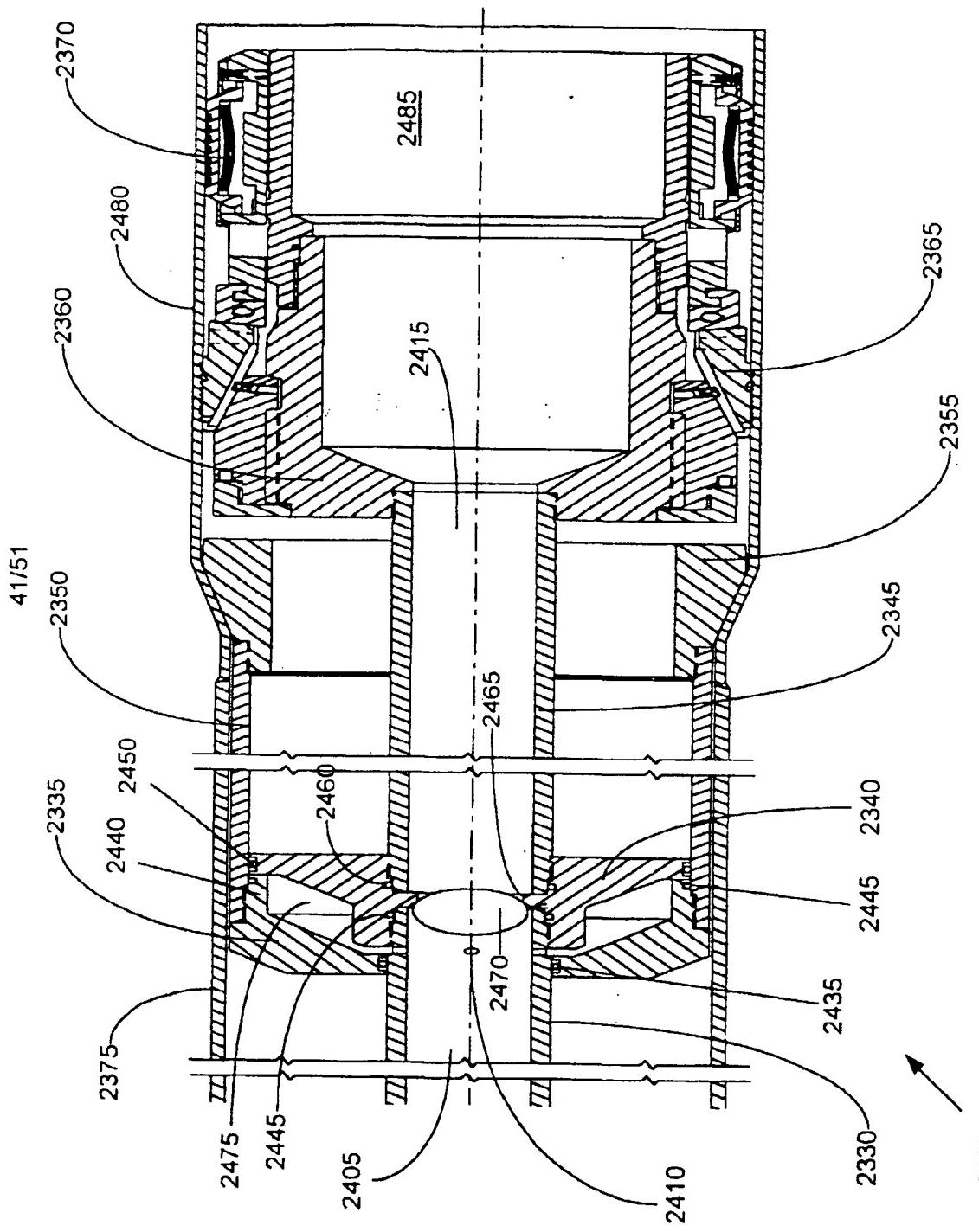


FIGURE 17b

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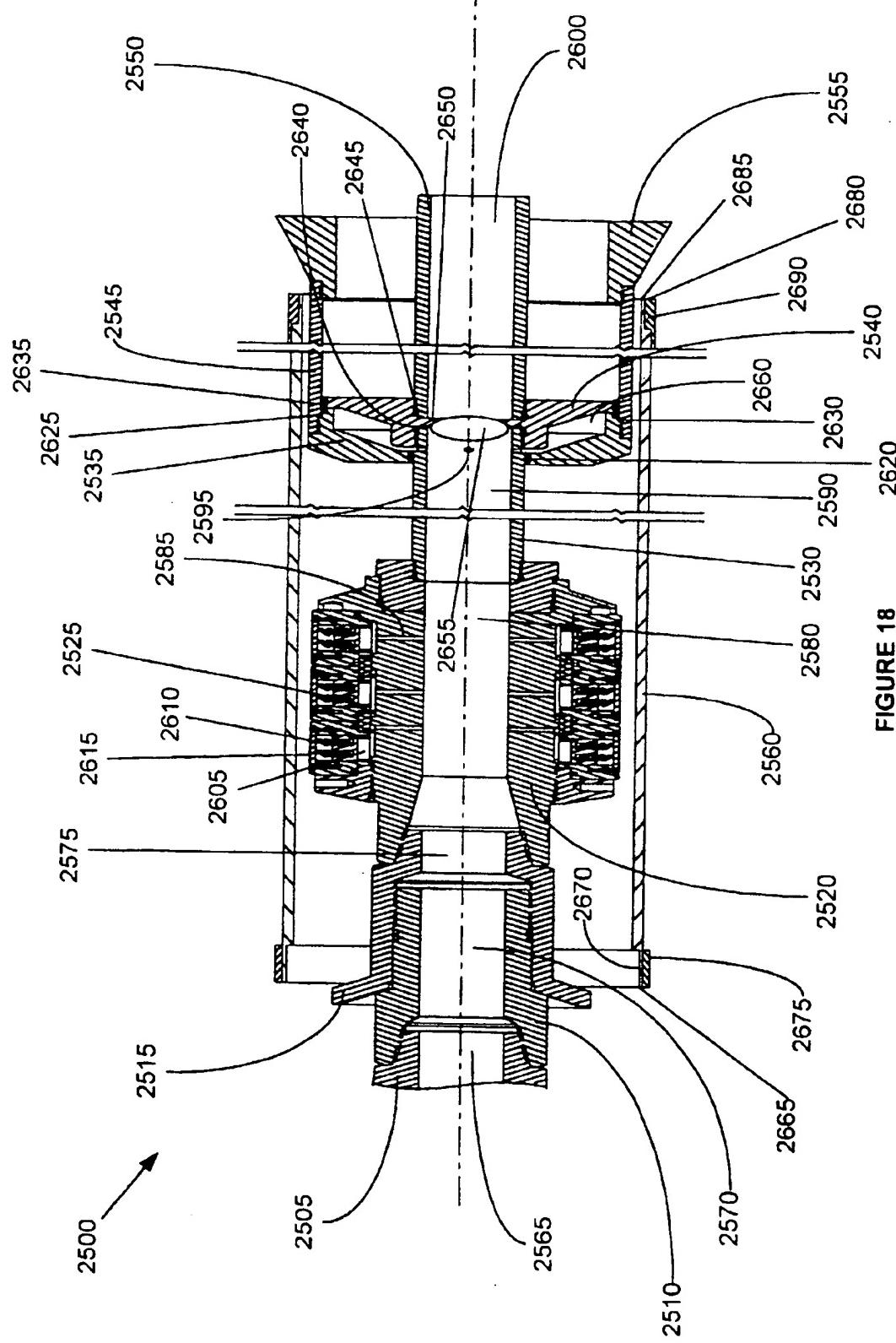


FIGURE 18

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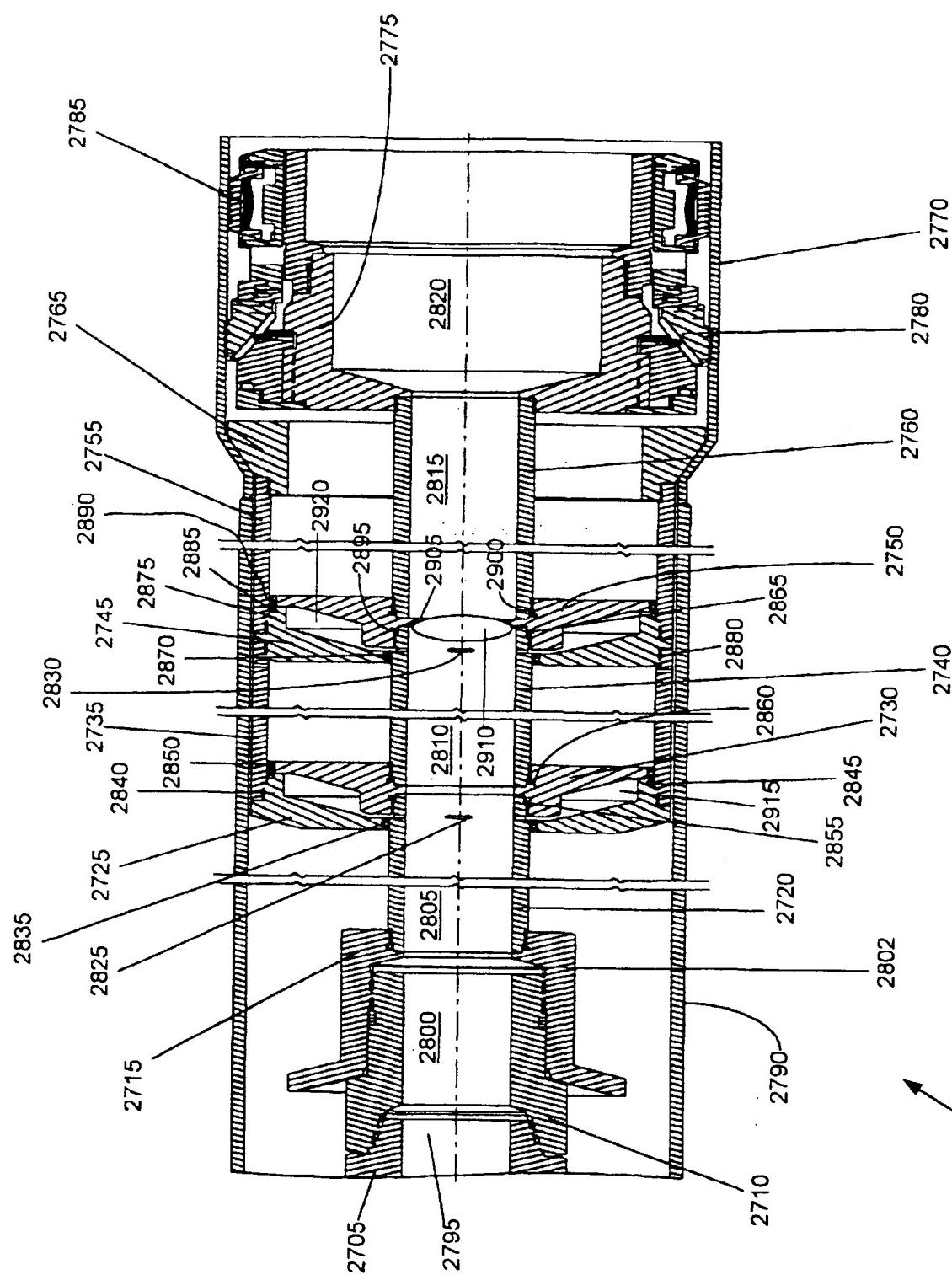


FIGURE 19

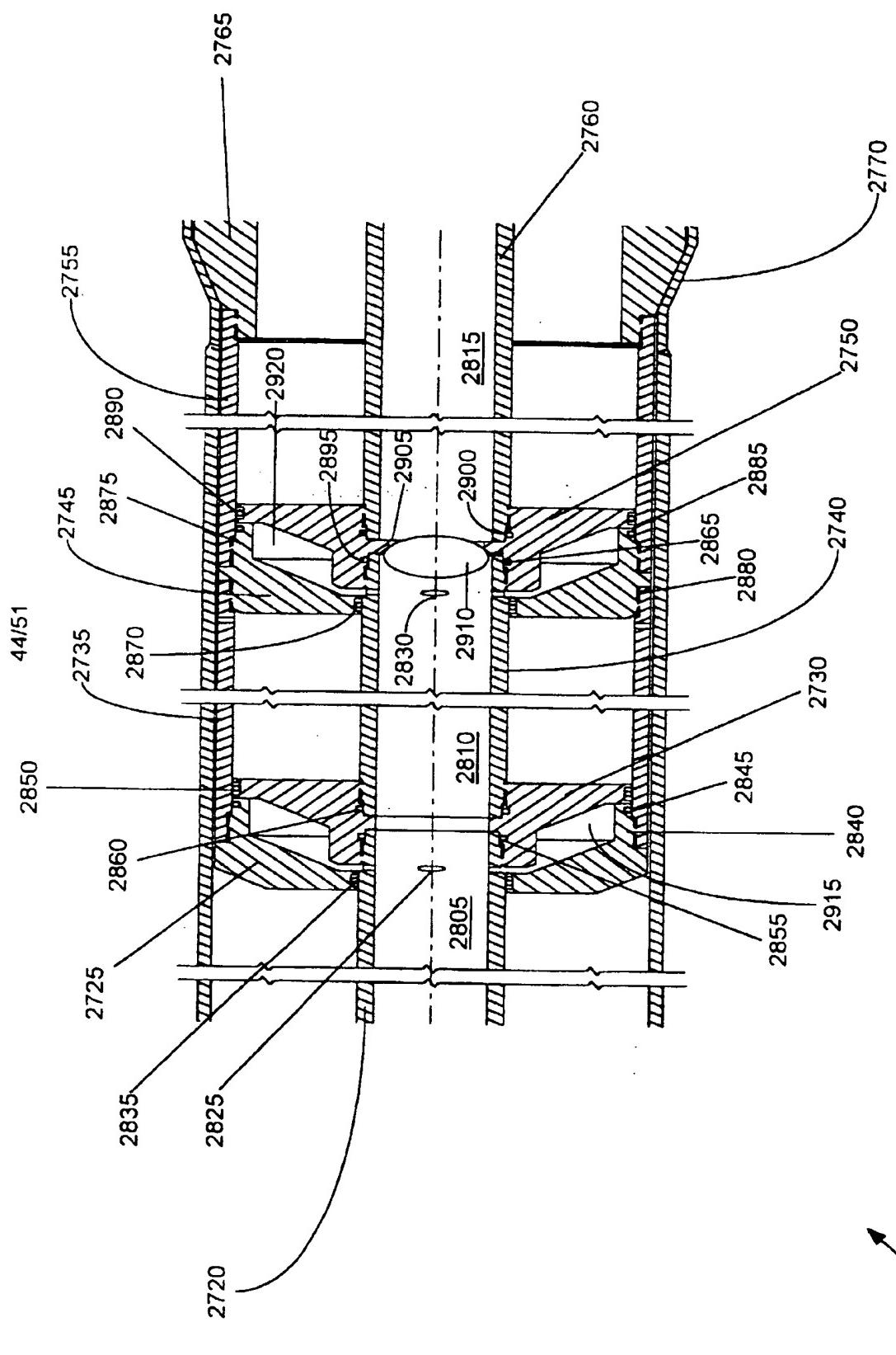


FIGURE 19a

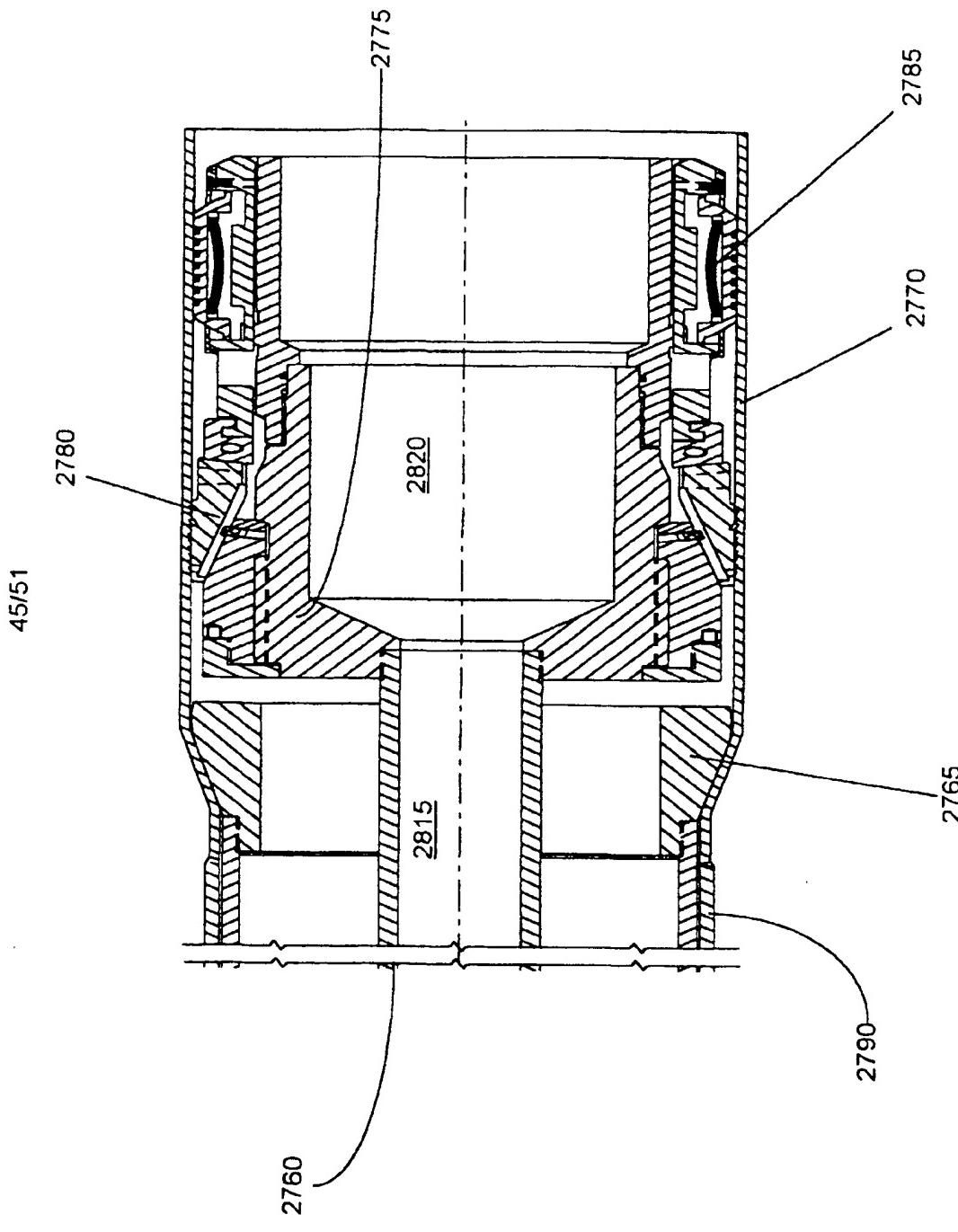


FIGURE 19b

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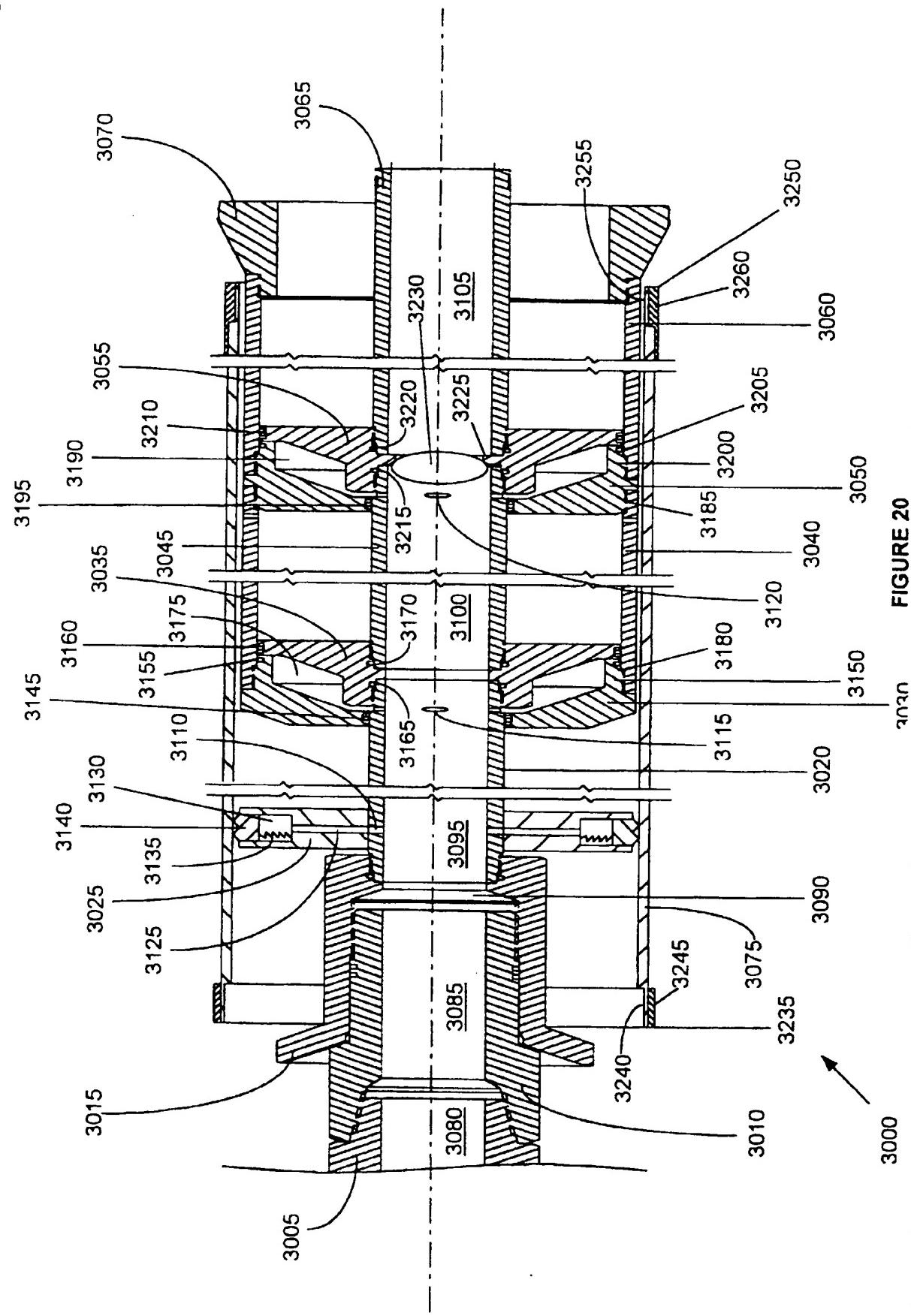


FIGURE 20

3030

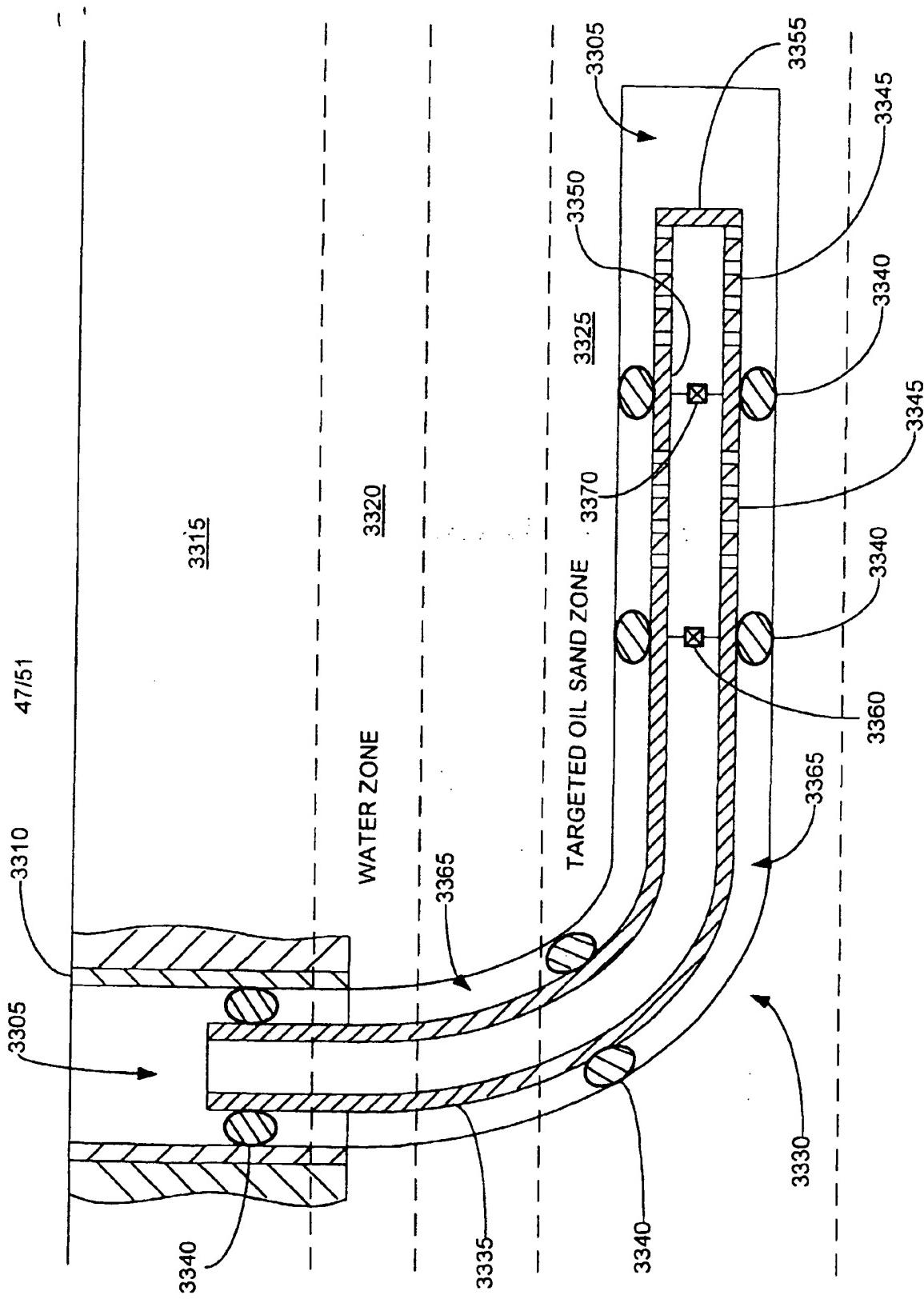


FIGURE 21

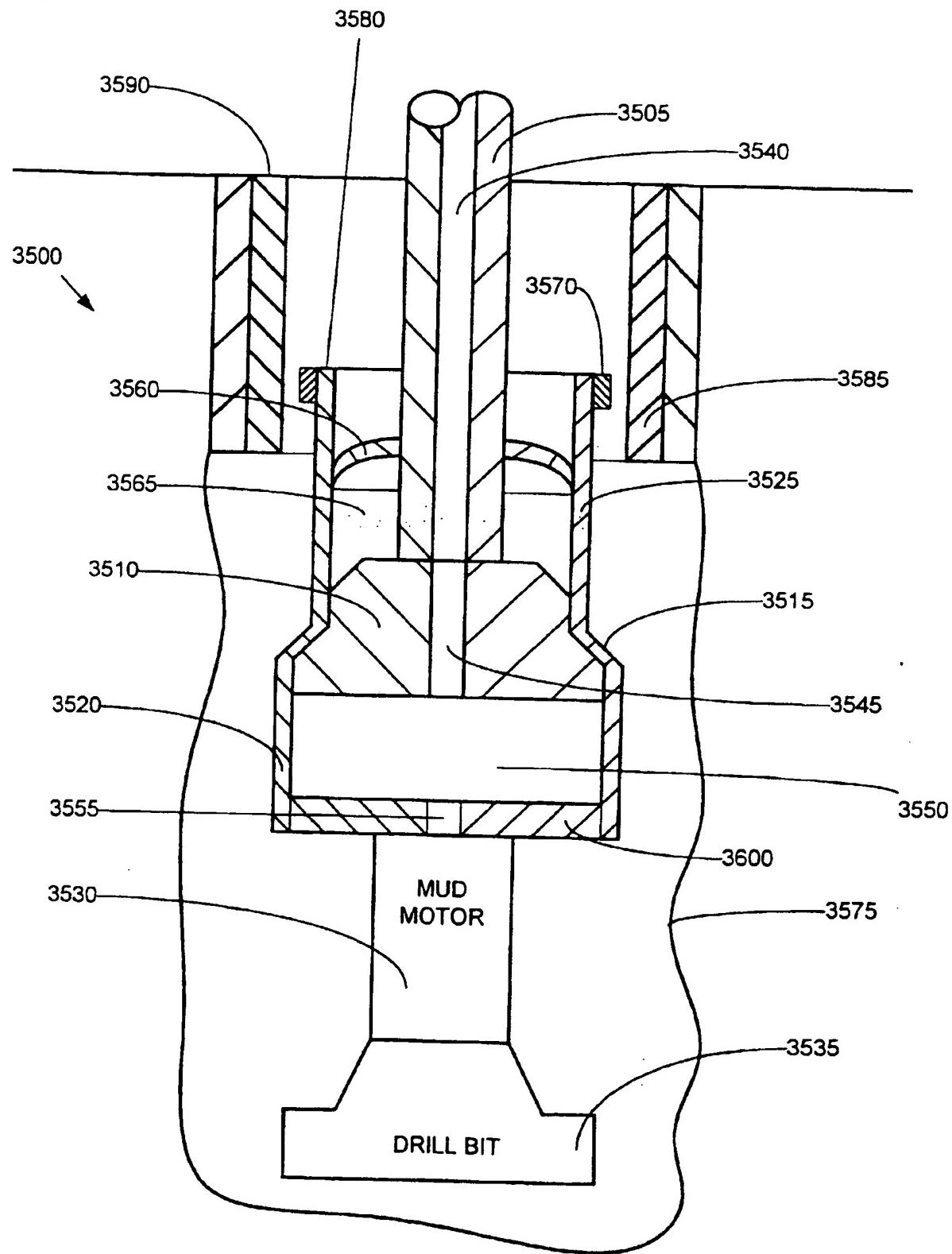


FIGURE 22A

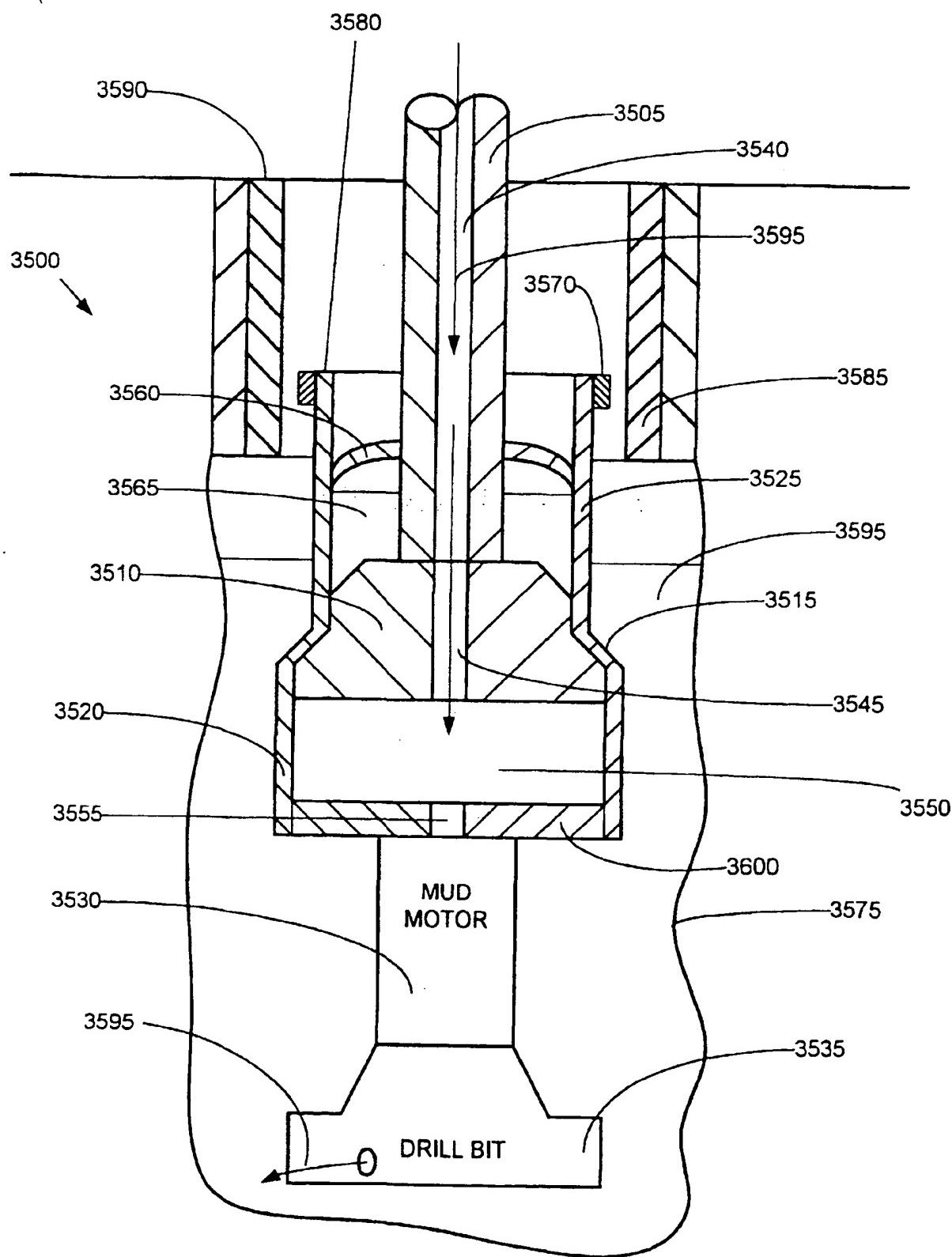


FIGURE 22B

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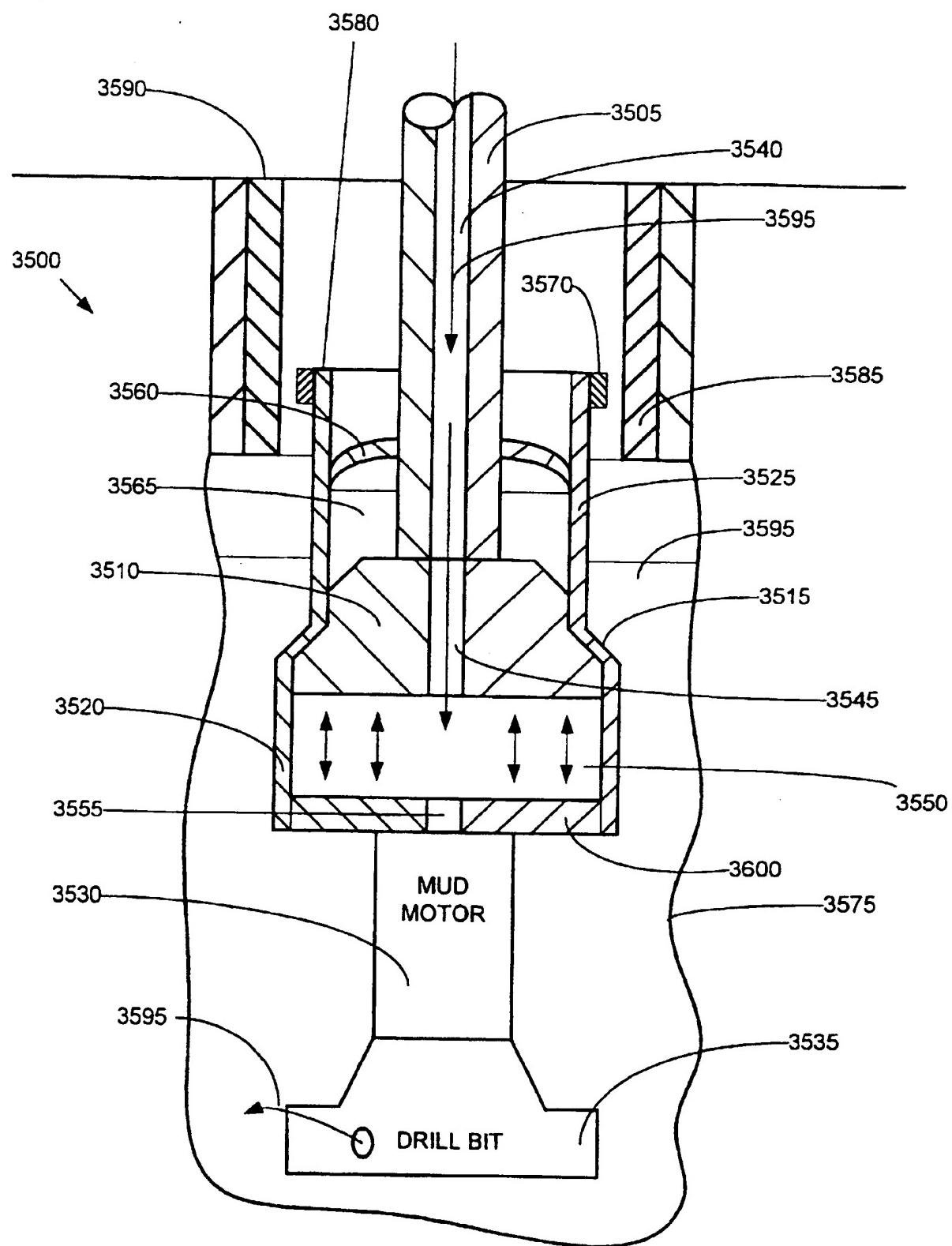


FIGURE 22C

wellbore casing is formed simultaneous with the drilling out of a new section of wellbore.

During the operation of the apparatus 3500, the apparatus 3500 is lowered into the wellbore 3575 until the drill bit 3535 is proximate the bottom of the wellbore 3575.

5 Throughout this process, the tubular member 3525 is preferably supported by the mandrel 3510. The apparatus 3500 is then lowered until the drill bit 3535 is placed in contact with the bottom of the wellbore 3575. At this point, at least a portion of the weight of the tubular member 3525 is supported by the drill bit 3535.

The fluidic material 3595 is then pumped into the first fluid passage 3540, 10 second fluid passage 3545, pressure chamber 3550, third fluid passage 3555, and the inlet of the mud motor 3530. The mud motor 3530 then drives the drill bit 3535 to drill out a new section of the wellbore 3575. Once the differential pressure across the mud motor 3530 exceeds the minimum extrusion pressure for the tubular member 3525, the tubular member 3525 begins to extrude off of the mandrel 3510. As the tubular member 3525 is extruded off of the mandrel 3510, the weight of the extruded portion of the tubular member 3525 is transferred to and supported by the drill bit 3535. The pumping pressure of the fluidic material 3595 is maintained substantially constant throughout this process. At some point during the process of extruding the tubular member 3525 off of the mandrel 3510, a sufficient portion of the weight of the tubular member 3525 is transferred to the drill bit 3535 to stop the extrusion process due to the opposing force. Continued drilling by the drill bit 3535 eventually transfers a sufficient portion of the weight of the extruded portion of the tubular member 3525 back to the mandrel 3510. At this point, the extrusion of the tubular member 3525 off of the mandrel 3510 continues. In this manner, the support member 3505 never has to be moved and no drillpipe connections have to be made at the surface since the new section of the wellbore casing within the newly drilled section of wellbore is created by the constant downward feeding of the expanded tubular member 3525 off of the mandrel 3510.

Once the new section of wellbore that is lined with the fully expanded tubular member 3525 is completed, the support member 3505 and mandrel 3510 are removed from the wellbore 3575. The drilling assembly including the mud motor 3530 and drill

bit 3535 are then preferably removed by lowering a drillstring into the new section of wellbore casing and retrieving the drilling assembly by using the latch 3600. The expanded tubular member 3525 is then cemented using conventional squeeze cementing methods to provide a solid annular sealing member around the periphery of 5 the expanded tubular member 3525.

Alternatively, the apparatus 3500 may be used to repair or form an underground pipeline or form a support member for a structure. The teachings of the apparatus 3500 are combined with the teachings of the arrangements illustrated in Figures 1-21. For example, by operably coupling the mud motor 3530 and drill bit 3535 to the pressure 10 chambers used to cause the radial expansion of the tubular members of the arrangements illustrated and described with reference to Figures 1-21, the use of plugs may be eliminated and radial expansion of tubular members can be combined with the drilling out of new sections of wellbore.

Registered Trade Marks

Lubriplate to Lubriplate (RTM)
Teflon to Teflon (RTM)

5

Non-Metric Units

0.75 to 47 inches and 1.05 to 48 inches (1.905 to 119.38 centimetres and 2.667 to 121.92 centimetres)

10 40 to 20,000 feet (12.192 to 6096.00 meters)

0 to 3,000 gallons/minute and 0 to 9,000 psi (0 to 11356.24 litres/minute and 0 to 620.528 bar)

1,000 to 1,000 000 lbf (.478803 to 478.803 bar)

15 0 to 5,000 psi and 0 to 1,500 gallons/minute (0 to 344.738 bar and 0 to 5618.12 litres/minute)

400 to 10,000 psi and 30 to 4,000 gallons/min (27.58 to 689.476 bar and 113.56 to 15141.68 litres/minute)

500 to 9,000 psi and 40 to 3,000 gallons/min (34.47 to 620.53 bar and 151.42 to 11356.24 litres/minute)

20 500 to 9,000 psi (34.47 to 620.53 bar)

0 to 5 ft/sec (1.524 meters)

0 to 2 ft/sec (.6096 meters)

50 to 20,000 psi (3.447 to 137.95 bar)

400 to 10,000 psi (27.58 to 689.476 bar)

25 5 feet (1.524 meters)

1.05 to 48 inches and 1/8 to 2 inches (2.667 to 121.92 and .3175 to 5.08 centimetres)

3.5 to 16 inches and 3/8 to 1.5 inches (8.89 to 40.64 centimetres and .9525 to 3.81)

2.5 to 50 inches and 1/16 to 1.5 inches (6.35 to 127 centimetres and .159 to 3.81 centimetres)

30 3.5 to 19 inches and 1/8 to 1.25 (8.89 to 48.26 and .3175 to 3.175 centimetres)

40 to 3,000 gallons/minute and 500 to 9,000 psi (151.42 to 11356.24 litres/minute and 34.47 to 620.53 bar)

0 to 500 gallons/minute and 0 to 1,000 psi (0 to 1892.705 litres/minute and 0 to 68.95 bar)

35 40,000 to 135,000 psi (2757.90 to 9307.92 bar)

1/16 to 1.5 inches (.159 to 3.81 centimetres)

1/8 to 1.25 in (.3175 to 3.175 centimetres)

1.05 to 48 inches (2.667 to 121.92 centimetres)

3 1/2 to 19 inches (8.89 to 48.26 centimetres)

40 2 to 5 feet (.6096 to 1.524 meters)

0 to 9,000 psi (0 to 620.528 bar)

0.125 to 3 inches (.3175 to 7.62 centimetres)

0.25 to 0.75 (0.635 to 1.905 centimetres)

1 to 47 inches (2.54 to 119.38 centimetres)

45 3.5 to 19 in (8.89 to 48.26 centimetres)

1,200 to 8,500 psi (82.737 to 586.054 bar)

- 40 to 1250 gallons/minute (151.416 to 4,731.765 litres/minute)
3 to 15.5 inches and 3.5 to 16 inches (7.62 to 39.37 and 8.89 to 40.64 centimetres)
500 to 10,000 psi (34.47 to 689.48 bar)
3/8 to 1 $\frac{1}{2}$ inches and 3 $\frac{1}{2}$ to 16 inches (.9525 to 3.81 and 8.89 to 40.64 centimetres)
5 0.625 to 0.75 inches and 3 to 19 inches (1.5875 to 1.905 and 7.62 to 48.26 centimetres)
3/8 to 1.5 inches and 3.5 to 16 inches (.9525 to 3.81 and 8.89 to 40.64 centimetres)
5,000 to 20,000 psi (344.737 to 1,378.951 bar)
0.125 to 1.5 inches (.3175 to 3.81 centimetres)

CLAIMS

1. An apparatus, comprising:
 - a wellbore, the wellbore formed by the process of drilling the wellbore; and
 - a tubular liner positioned within the wellbore, the tubular liner formed by the process of extruding the tubular liner off of a mandrel while drilling the wellbore with a drill bit coupled to a downhole motor operably coupled to the mandrel.
2. The apparatus of claim 1, wherein extruding the tubular liner off of the mandrel comprises:
 - 10 injecting a fluidic material into the wellbore.
3. The apparatus of claim 2, wherein the injecting comprises:
 - 15 injecting a non hardenable fluidic material into an interior region of the tubular liner below the mandrel.
4. The apparatus of claim 3, further comprising:
 - 20 fluidically isolating an annular region from the interior region before injecting the non hardenable fluidic material into the interior region.
5. The apparatus of claim 3, wherein the injecting of the non hardenable fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min (34.47 to 620.53 bar and 151.42 to 11356.24 litres/minute).
6. The apparatus of claim 3, wherein the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the extruding.
7. The apparatus of claim 2, wherein the fluidic material is injected below the mandrel.

8. The apparatus of claim 1, wherein a region of the tubular liner below the mandrel is pressurized.

5 9. The apparatus of claim 8, wherein the region of the tubular liner below the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi (34.47 to 620.53 bar).

10 10. The apparatus of claim 2, further comprising:
fluidically isolating an interior region of the tubular liner from an exterior region
of the tubular liner.

11. The apparatus of claim 10, wherein the interior region of the tubular liner is isolated from the region exterior to the tubular liner by inserting one or more plugs into the injected fluidic material.

15 12. The apparatus of claim 1, further comprising:
maintaining the mandrel in a substantially stationary position during the extrusion of the tubular liner and the drilling out of the wellbore.

20 13. The apparatus of claim 1, further comprising:
overlapping the tubular liner with an existing wellbore casing.

14. The apparatus of claim 13, further comprising:
sealing the overlap between the tubular liner and the existing wellbore casing.

25 15. The apparatus of claim 14, further comprising:
supporting the extruded tubular liner using the overlap with the existing wellbore casing.

30 16. The apparatus of claim 14, further comprising:

testing the integrity of the seal in the overlap between the tubular liner and the existing wellbore casing.

17. The apparatus of claim 1, further comprising:

5 lubricating the surface of the mandrel.

18. The apparatus of claim 1, further comprising:

absorbing shock.

10 19. The apparatus of claim 1, further comprising:

catching the mandrel upon the completion of the extruding.

20. The apparatus of claim 1, further comprising expanding the mandrel in a radial direction.

15

21. The apparatus of claim 1, further comprising:

drilling out the mandrel.

22. The apparatus of claim 1, further comprising:

supporting the mandrel with coiled tubing.

23. The apparatus of claim 1, wherein the wall thickness of the tubular liner is variable.

25 24. The apparatus of claim 1, further comprising:

applying a variable axial force to the bottom of the wellbore.

25. An apparatus, comprising:

a wellbore;

30 a tubular liner positioned within the wellbore;

a non-rotating mandrel coupled to the tubular liner positioned within the wellbore and within the tubular liner; and
a drill bit operably coupled to the tubular liner;
wherein the tubular liner is formed by the process of extruding the tubular liner off of the mandrel while drilling the wellbore using the drill bit.

26. An apparatus, comprising:

a wellbore;
a tubular liner positioned within the wellbore;
10 a mandrel positioned within the wellbore and within the tubular liner; and
a drill bit operably coupled to the tubular liner positioned within the wellbore;
wherein the tubular liner is formed by the process of extruding the tubular liner off of the mandrel while drilling the wellbore using the drill bit; and
wherein there is a relative rotation between the mandrel and the drill bit.

15

27. An apparatus, comprising:

a wellbore;
a tubular liner positioned within the wellbore;
a mandrel positioned within the wellbore and within the tubular liner; and
20 a drill bit positioned within the wellbore, the drill bit continuously operably coupled to the mandrel;
wherein the tubular liner is formed by the process of extruding the tubular liner off of the mandrel while drilling the wellbore using the drill bit.

25 28. The apparatus of claim 25, 26 or 27, wherein the mandrel is expandable in a radial direction.

ABSTRACT

An apparatus, comprising: a wellbore, the wellbore formed by the process of drilling
the wellbore; and a tubular liner positioned within the wellbore, the tubular liner
5 formed by the process of extruding the tubular liner off of a mandrel while drilling the
wellbore.

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